135

0924

Walden
RESEARCH CORPORATION

PB 207 110

FINAL REPORT

SYSTEMATIC STUDY OF AIR POLLUTION FROM INTERMEDIATE-SIZE FOSSIL-FUEL COMBUSTION EQUIPMENT

Contract No. CPA 22-69-85
ENVIRONMENTAL PROTECTION AGENCY

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
Springfield, Va. 22151

July 1971

toward a better enviro

BIBLIOGRAPHIC DATA SHEET

1. Report No. APTD-0924

2.

3. Recipient's Accession No.

4. Title and Subtitle

Systematic Study of Air Pollution from Intermediate-Size Fossil-Fuel Combustion Equipment

5. Report Date July 1971

6.

7. Author(s) John R. Ehrenfeld, Ralph H. Bernstein, et al

8. Performing Organization Rept. No.

9. Performing Organization Name and Address

Walden Research Corporation
359 Allston Street
Cambridge, Massachusetts 02139

10. Project/Task/Work Unit No.

11. Contract/~~Grant~~ No. CPA 22-69-85

12. Sponsoring Organization Name and Address

Environmental Protection Agency
Air Pollution Control Office
3914 Virginia Avenue
Cincinnati, Ohio

13. Type of Report & Period Covered Final

14.

15. Supplementary Notes

16. Abstracts

A basis is provided for assessing the relative significance of this class of sources and for establishing a research and development plan to develop control means. The pollutant sources are identified according to equipment type and size, regional distribution, fuel, user, age and other factors of significance to air pollution emissions. Estimates of installed capacity were made for the base year - 1967, with projections for 1975, 1980, 1985, and 1990. Only intermediate-size conventional boilers were included (all steam-raising equipment, hot water heaters and hot air furnaces used for space heating larger in capacity than residential units (200,000 Btu/hr) and smaller than that equivalent to 50 megawatts electrical (500,000 pounds of steam per hour). Boilers were broken down according to type and size as: watertube (four sizes); firetube; cast iron; and residential. Equipment in the excluded categories was included in the basic capacity inventory to permit comparison between calculated fuel use and statistical sales data. Annual emissions of SO_2, NO_x and particulates were computed by applying a series of operating factors (boiler efficiency, load factor, etc.) to the capacity inventory using a computer program (STRAT). The identification and the analysis of the cost-effectiveness of possible control approaches was also made. The major strategies examined included: fuel switching; flue gas treatment; and combution modification. Process designs and costs data were developed for application of these strategies to intermediate-size boilers. The STRAT program was used to assess the relative cost and effect on pollutant reduction of a variety of different strategies. Strategies affecting the combined pollutant burden were examined, as well as approaches for each of the separate pollutants.

17. Key Words and Document Analysis. 17a. Descriptors

Air pollution
Fuels
Exhaust emissions
Boilers
Heating equipment
Furnaces
Residential buildings
Sulfur dioxide
Nitrogen oxides
Particles
Computer programs
Expenses
Flue gases
Combustion
Research projects
Environments
Revisions

17b. Identifiers/Open-Ended Terms

17c. COSATI Field/Group 13B

18. Availability Statement

Unlimited

19. Security Class (This Report) UNCLASSIFIED

20. Security Class (This Page UNCLASSIFIED

21. No. of Pages 340

22. Price

ERRATA SHEET

TO

FINAL REPORT UNDER CONTRACT NO. CPA 22-69-85

SYSTEMATIC STUDY OF AIR POLLUTION FROM INTERMEDIATE-SIZE FOSSIL-FUEL COMBUSTION EQUIPMENT

Page 180 (Table 5-12)

Insert in the second to last row (Coal, Stoker) the following data, under the appropriate column headings as given below:

Column A, New	165
Column A, Conversion	200
Column E, New	110
Column E, Conversion	150

Page 227 (Table 6-10)

Substitute under the column entitled, "1975 Demand with Switching" the following data:

231 for 670
680 for 918
8.3 for 16.9

WALDEN RESEARCH CORPORATION

FINAL REPORT

SYSTEMATIC STUDY OF AIR POLLUTION FROM INTERMEDIATE-SIZE FOSSIL-FUEL COMBUSTION EQUIPMENT

Contract No. CPA 22-69-85

by
John R. Ehrenfeld
Ralph H. Bernstein
Katherine Carr
Josette C. Goldish
Ronald G. Orner
Thomas Parks

July 1971

Prepared by
Walden Research Corporation
359 Allston Street
Cambridge, Mass. 02139

Prepared for
Air Pollution Control Office
Environmental Protection Agency
3914 Virginia Avenue
Cincinnati, Ohio

FOREWORD AND ACKNOWLEDGMENT

This final report is tendered under Contract No. CPA 22-69-85, sponsored by the Air Pollution Control Office of the Environmental Protection Agency.

The project director was Dr. John R. Ehrenfeld. The Walden project staff included:

Ralph H. Bernstein
Katherine Carr
Josette Goldish
Ronald Orner
Thomas Parks

Acknowledgment of the contributions of two consultants to Walden, Professors William Dalzell and Geoffrey Margolis of the MIT Chemical Engineering Department is made.

Substantial assistance and guidance were contributed by Mr. J. Robert Day, James Dorsey, G. Blair Martin, and E. E. Berkau, all of the Air Pollution Control Office (formerly NAPCA). Both Mr. Day and Mr. Martin served as project officers.

The extensive efforts by three subcontractors, Riley Stoker Corporation, Stone and Webster Engineering Corporation, and Urban Analysis Corporation are acknowledged. Riley Stoker has provided data on all aspects of utilization, sales background, and engineering characteristics of industrial and utility boilers. Stone and Webster has contributed mainly in developing costs and specifications for flue gas treatment processes fitting intermediate-size equipment. Urban Analysis Corporation determined the regional breakdown used, and provided the data base used to develop the projections.

TABLE OF CONTENTS (continued)

Section | Title | Page

ADDITIONAL REFERENCES (UNCITED) FOR PARTICULATES CONTROL 203

ADDITIONAL REFERENCES (UNCITED) FOR SO_2 CONTROL 205

ADDITIONAL REFERENCES (UNCITED) FOR NO_x CONTROL 207

VI COST-EFFECTIVENESS ANALYSIS 208

- A. Introduction 208
- B. Watertube Boilers 209
- C. Firetube and Cast Iron Boilers 211
- D. All Intermediate-Size Boilers 213
- E. Sensitivity to Fuel Price on the Trade-Off Between Fuel Switching and Flue Gas Treatment 213
- F. Economic Impact on Users 217
- G. Supplementary Strategies 220
- H. Maximum Reduction-Reasonable Cost Total Program .. 222
- I. Influence of Fuel Supply 224

REFERENCES TO SECTION VI 232

VII RECOMMENDATIONS 233

- A. Improvements of the Present Study 233
- B. Implementation of Fuel Switching 236
- C. Alternative Approaches 239

APPENDIX A METHODOLOGY FOR GENERATING EMISSION ESTIMATES A-1

- A. STRAT Program A-1
- B. Sources of Data on Boiler Capacity A-6
- C. Other Factors in the STRAT Program A-14

REFERENCES TO APPENDIX A A-40

APPENDIX B METHODOLOGY FOR PROJECTIONS B-1

- A. Regression Analysis B-1
- B. Sales Projections B-7
- C. Retirements B-11
- D. Projections of Installed Capacity B-11
- E. Regional, Fuel, User Distribution B-15
- F. Projections of Demographic and Economic Factors .. B-19
- G. Linear Fuel Projections B-23

REFERENCES TO APPENDIX B B-34

APPENDIX C SUMMARY DATA TABLES OF SELECTED STRATEGIES C-1

TABLE OF CONTENTS

Section	Title	Page
I	SUMMARY	1
	A. Background, Objectives and Approach	1
	B. Base-Year Inventory of Boiler Capacity, Fuel Use, and Emissions	3
	C. Projections of Boiler Capacity, Fuel Use, and Emissions	12
	D. Control Strategies	23
	E. Recommendations	35
	REFERENCES TO SECTION I	40
II	INTRODUCTION	41
	REFERENCES TO SECTION II	45
III	INVENTORY OF BOILER CAPACITY, FUEL USE, AND EMISSIONS	46
	A. Methodology	46
	B. Definitions	47
	C. Results	55
	REFERENCES TO SECTION III	74
IV	DISCUSSION OF 1967 ESTIMATES AND PROJECTIONS	76
	A. Methodology and Assumptions	76
	B. Projections of Boiler Inventory to 1975, 1980, 1985, 1990	78
	C. Projected Emissions	85
	D. Geographic Results	97
	E. Fuel Use	102
	REFERENCES TO SECTION IV	126
V	STRATEGIES FOR EMISSION ABATEMENT	128
	A. Introduction	128
	B. Fuel Switching	128
	C. Flue Gas Treatment	142
	D. Combustion Design	183
	E. Strategy Characteristics	197
	REFERENCES TO SECTION V	199

LIST OF ILLUSTRATIONS

Figure	Caption	Page
1-1	Regional Boundaries	7
1-2	Combined Emissions (1967) from Intermediate Boilers - By Type and Fuel	13
1-3	Effect of Projected Control Levels on SO_2 Emissions	21
1-4	Effect of Projected Control Levels on NO_x Emissions	22
1-5	Projected Reduction in 1975 Emission Levels from Fuel Switching	31
1-6	Cost Comparison of Alternate Strategies for Watertube Boilers	33
3-1	Regional Boundaries	52
3-2	1967 Total Boiler Capacity by User	57
3-3	1967 Intermediate Boiler Capacity - Regional by User	58
3-4	1967 Emissions - Regional Distribution	60
3-5	1967 Emissions from All Boilers by User	61
3-6	1967 Emissions from Intermediate Boilers by User	62
3-7	Combined Emissions (1967) from Intermediate Boilers - By Type and Fuel	64
3-8	Combined Emissions (1967) from Intermediate Boilers - By Size	65
3-9	Combined Emissions (1967) from Intermediate Boilers - By User	66
3-10	Combined Emissions (1967) from Intermediate Boilers - Coal-Fired by Region	67
3-11	Capacity of Intermediate Boilers - By Type	68
4-1	Projected Boiler Capacity by Type	81
4-2	Projected Total and Intermediate Boiler Capacity	83
4-3	Projected Boiler Capacity by User	84
4-4	Projected Particulate Annual Emission (controlled)	87
4-5	Projected Particulate Annual Emission (uncontrolled)	88
4-6	Projected SO_2 Emission	89
4-7	Projected NO_x Annual Emission	90
4-8	Effect of Projected Control Levels on SO_2 Emissions	91
4-9	Effect of Projected Control Levels on NO_x Emissions	93

LIST OF ILLUSTRATIONS (continued)

Figure	Caption	Page
4-10	Projected Fuel Consumption - All Boilers	107
4-11	Fuel Consumption in Intermediate and in All Boilers	108
4-12	Projected Fuel-by-Fuel Consumption - Intermediate Boilers	109
4-13	1967 Total Fuel Consumption by Fuel and User	113
4-14	1967 Fuel Consumption in Boilers by Fuel and User	119
5-1	Capital Cost for Fuel Oil Storage and Handling	139
5-2	Types of Collection Equipment	143
5-3	Capital Cost - Particulate Collection System	146
5-4	SO_2 Removal with Dry Sodium Carbonate - Bag Filter (Scheme A)	170
5-5	SO_2 Removal with Sodium Carbonate - Wet Scrubbing (Scheme B)	171
5-6	SO_2 Removal with Dry Calcium Carbonate - Precipitators (Scheme C)	172
5-7	SO_2 Removal with Dry Calcium Carbonate - Scrubbing (Scheme D)	173
5-8	SO_2 Removal with Wet Calcium Carbonate - Scrubbing (Scheme E)	174
5-9	SO_2 Removal with Calcium Oxide - Scrubbing (Scheme F) ..	175
5-10	Typical NO_x Emissions as Function of Excess Air	193
6-1	Cost Comparison of Alternate Strategies for Watertube Boilers	216
6-2	Cost Effectiveness of Strategies for Combined Emission Control	226
A-1	STRAT Flow Chart	A-2
A-2	Summary of the 1967 Boiler Inventory	A-7
B-1	Projected Inventory Distribution Flow Sheet	B-2
B-2	Historical and Projected Sales of Watertube Boilers, 100,001-250,000 pph	B-10
B-3	Projected Percentage of Watertube Boilers >500,000 pph in the Set >250,000 pph	B-14

LIST OF TABLES

Table	Title	Page
1-1	1967 Capacity and Fuel Summary	5
1-2	Regional Distribution of Intermediate Boilers	6
1-3	1967 Emissions Summary	9
1-4	1967 Emissions from Intermediate Boilers by Region	10
1-5	Capacity of Boilers by Type and User	16
1-6	Projected Fuel Use (Quantity Units) - U.S. Totals	17
1-7	Emission Estimates - Total U.S. Fossil Fuel Fired Boilers	19
1-8	Distribution of Units in Fuel Switching Strategy	30
1-9	Alternative Strategies for Intermediate Boilers	32
1-10	Cost of Strategies - WT Boilers Only	34
3-1	Boiler Classes and Codes	49
3-2	1967 Summary of Results	56
3-3	1967 Utilities SO_2 Emissions	70
3-4	1967 Ranking of SO_2 Emissions	70
3-5	1967 Utilities NO_x Emissions	71
3-6	1967 Ranking of NO_x Emissions	71
3-7	1967 Utilities Particulate Emissions	72
3-8	1967 Ranking of Controlled Particulate Emissions	72
4-1	Projected Capacity of Boilers by Type and User	79
4-2	Projected Number of Boilers by Type	80
4-3	Projected Average Size of Boilers	86
4-4	Assumed SO_2 Control Levels for Large Boilers	92
4-5	NO_x from Power Plants	96
4-6	Priority Indexes	100
4-7	Trends in Emissions from Intermediate Boilers 1967-1990	101
4-8	Calculated Fuel Use (Heating Value) U.S. Totals	103
4-9	Calculated Fuel Use (Quantity Units) U.S. Totals	104
4-10	Utility Projections	106
4-11	National Fuel Shares (Intermediate-Size Boilers Only)	110
4-12	Percentage of Fuel in Manufacturing Used in Boilers	114

LIST OF TABLES (continued)

Table	Title	Page
4-13	Percent of Fuel Burned in Boilers According to User	117
4-14	Annual Fuel Burned under Boilers	118
4-15	Residential - Fuel Consumption in Boilers in 10^{15} Btu ...	121
4-16	Commercial - Fuel Consumption in Boilers in 10^{15} Btu	122
4-17	Industrial - Fuel Consumption in Boilers in 10^{15} Btu	123
4-18	Utilities - Fuel Consumption in Boilers in 10^{15} Btu	124
5-1	Fuel Rates	131
5-2	Costs of Converting from Coal Firing to Gas/Oil	136
5-3	Total Capital Cost of Converting Coal-Fired Boilers	141
5-4	Conversion Factor for Steam Flow to Flue Gas Flow and Excess Air	149
5-5	L - Liquor (Water) Cost	149
5-6	E - Fan Efficiency (Including Motor)	150
5-7	F - Pump Efficiency (Including Motor)	150
5-8	Factors for Annual Capital Cost and Maintenance	151
5-9	Electric Power Costs	151
5-10	Assumed Collector Efficiencies for Coal-Fired Units	152
5-11	SO_2 Removal Systems for Intermediate Boilers	169
5-12	Sulfur Dioxide Removal from Fossil Fuel Boiler Flue Gas .	180
5-13	Sulfur Dioxide Removal from Fossil Fuel Boiler Flue Gas .	181
5-14	Combustion Additives - Typical Examples and Applications	185
5-15	Add-On Cost of Combustion Modification	195
6-1	Fuel Switching Strategy on Watertube Sizes	210
6-2	Flue Gas Treatment Strategy on Watertube Sizes	212
6-3	Fuel Switching Strategy on FT and CI Boilers	214
6-4	Fuel Switching Strategy on All Intermediate Boilers	215
6-5	Capital Cost Estimates for Replacement of Coal Fired Equipment	218
6-6	Alternative Capital Cost Requirements	219
6-7	Fuel Switching Strategy Operating Cost - Fuel Only	220
6-8	Combustion Design Strategy on All Intermediate Boilers ..	223
6-9	Overall Composite Program for All Intermediate Boilers ..	225

LIST OF TABLES (continued)

Table	Title	Page
6-10	Fuel Demand with Switching - 1975 - Intermediate Boilers Only	227
A-1	Watertube Boilers in Use in 1967	A-13
A-2	Firing Distribution Table	A-14
A-3	Boiler Efficiency Table	A-16
A-4	Load Factor Determination (For Space Heating)	A-18
A-5	Load Factor Table	A-22
A-6	Fuel Characteristics Table	A-26
A-7	Emission Factor Table	A-28
A-8	Particulate Control 1967 Base Year Equipment Installations and Efficiencies	A-34
A-9	Particulate Collector Efficiency Table	A-35
B-1	Regression Analysis - Watertube Boilers $\leq$ 100,000 pph	B-5
B-2	Regression Analysis - Watertube Boilers 100,001-250,000 pph	B-6
B-3	Regression Analysis - Watertube Boilers >250,000 pph	B-7
B-4	Added Boilers	B-12
B-5	Retired Boilers	B-12
B-6	Projected Installed Capacity	B-13
B-7	Recent Large Boiler Sales (ABMA)	B-13
B-8	Households (1 to 4 units)	B-24
B-9	Employment - Manufacturing	B-24
B-10	Employment - Commercial	B-25
B-11	Industrial Output as a Proportion of 1967	B-25
B-12	Fuel Projections for Fuel Burned in Intermediate Boilers 1975	B-26
B-13	Fuel Projections for Fuel Burned in Intermediate Boilers 1980	B-28
B-14	Fuel Projections for Fuel Burned in Intermediate Boilers 1985	B-30
B-15	Fuel Projections for Fuel Burned in Intermediate Boilers 1990	B-32
C-1	Strategies for Particulate Reduction - 1975	C-5
C-2	Strategies for SO_2 Reduction - 1975	C-8
C-3	Strategies for NO_x Reduction - 1975	C-12

I. SUMMARY

A. BACKGROUND, OBJECTIVES AND APPROACH

The electric utility industry has been most often singled out as the principal stationary-source contributor to urban air pollution and, consequently, most attention to the development and application of control means has been directed toward those sources. This study resulted from concern that a significant portion of urban pollution levels was produced, not by large utility boilers above, but by large numbers of intermediate-size fossil-fuel burning installations. If so, a different set of control strategies and a different technology development and demonstration program would be required. Little was known about the gross capacity of these intermediate-size units, their fuel use and pollutant emissions and how differences in source location within urban bounds, or stack height and seasonal fluctuations affected their contribution to ground-level pollutant contribution relative to the large utility units.

Further, little consideration had been given to potential means to control pollution from these sources; emphasis on SO_2 control technology has been directed to large-scale processes applicable primarily to large (over 50 MW) electric utility boilers. This systems study of emissions from and control of intermediate-size fossil-fuel burning equipment was initiated to provide a basis for assessing the relative significance of this class of sources and for establishing a research and development plan to develop control means.

The first three phases of the study identified the pollutant sources according to equipment type and size, regional distribution, fuel, user, age and other factors of significance to air pollution emissions. Estimates of installed capacity were made for the base year - 1967, with projections for 1975, 1980, 1985, and 1990.

Only intermediate-size conventional boilers were included in this study, where the term "conventional boiler" has been defined to include all steam-raising equipment, hot water heaters and hot air furnaces used for space heating. "Intermediate size" has been defined to include equipment larger in capacity than residential units (200,000 Btu/hr) and smaller than that equivalent to 50 megawatts electrical (500,000 pounds of steam per hour).

Boilers were broken down according to type and size as:

(1) Watertube (four sizes)
(2) Firetube
(3) Cast iron
(4) Residential

Equipment in the excluded categories [residential and the largest watertube class (>500,000 pounds per hour)] was included in the basic capacity inventory to permit comparison between calculated fuel use and statistical sales data gathered by various government and private agencies.

Annual emissions of SO_2, NO_x and particulates were computed by applying a series of operating factors (boiler efficiency, load factor, etc.) to the capacity inventory using a computer program (STRAT) developed specially for that purpose. This approach differs from that taken in most emission estimates in that capacity, not fuel use, is the basic determinant. Comparisons with independent fuel use data were made to check the validity of this approach. No distinction between the composition of particulate from coal and oil or gas-fired units was made in building up the emission estimates and projections. The resulting emission estimates were examined to identify the most significant subclasses within the intermediate-size group.

The fourth phase was devoted to the identification and the analysis of the cost-effectiveness of possible control approaches. The major strategies examined included:

(1) Fuel switching
(2) Flue gas treatment
(3) Combustion modification

Process designs and cost data were developed for application of these strategies to intermediate-size boilers. The STRAT program was used to assess the relative cost and effect on pollutant reduction of a variety of different strategies composed of the above elements. Strategies affecting the combined pollutant burden were examined, as well as approaches for each of the separate pollutants.

The final phase was devoted to the development of a set of recommendations (1) for improvement of the present study, (2) for implementation of control measures, and (3) for a research and development plan to lead to new means of control to apply in future years.

B. BASE-YEAR INVENTORY OF BOILER CAPACITY, FUEL USE, AND EMISSIONS

1. Definitions, Assumptions, and Bases

a. Inventories were derived from historical sales and other statistical data assuming certain life-spans for the various boiler types. These life-spans were estimated by using sample data gathered on utility boilers and from interviews with boiler manufacturers and trade associations.

b. The estimates of emissions and fuel use were derived by converting the inventory of capacity by applying various operating factors according to Equation (1-1) below.

$$\text{Annual Emissions} = \text{capacity} \times \text{load factor} \times \text{boiler efficiency} \times \text{collector efficiency} \times \frac{1}{\text{fuel heating value}} \times \text{emission factor} \qquad (1\text{-}1)$$

Proper conversion factors to relate inventory in pounds of steam or Btu per hour to annual emissions are introduced in the calculation. Capacity itself is broken down by user, fuel, region, size, firing type and age. This approach permits introduction of the operating factors as functions of the various distributive variables and should result in more realistic results than estimates based only on gross fuel use.

c. Regional and other distributions (by user, fuel, etc.) were based on samples of equipment obtained from various publications and field trips. A major assumption was that these various samples were representative of the total boiler population.

d. It was assumed that the number of units and the wide scope of the study permitted the application of average operating characteristics as well as emission factors. Similarly, for the six broad regions, average fuel prices and characteristics by user category were considered sufficient.

e. No controls for SO_2 or NO_x were assumed in developing the 1967 estimates. Assumptions as to the degree of present particulate control were based on estimates and manufacturers' data. Recent fuel sulfur restrictions, which would limit SO_2 emissions, were not considered in the base year estimates.

2. 1967 Results

a. Capacity and Fuel Use

Table 1-1 summarizes the results of the 1967 inventory and fuel use estimates. Data on large utility boilers and residential units are included in the lower half of the table.

Regional fuel use variations as well as the regional capacity distribution are shown in Table 1-2. The regions used in this study are indicated in Figure 1-1.

The significant features in these results appear to be:

i. The installed capacity of intermediate-size boilers is split almost equally between commercial and industrial units with a lesser component of small utility boilers.

ii. The Atlantic, Great Lakes, and Far West and South regions represent approximately 75% of the U.S. capacity of intermediate

TABLE 1-1

1967 CAPACITY AND FUEL SUMMARY

	Capacity (million pph)	Coal (million tons)	Residual Oil (million bbls)	Distillate Oil (million bbls)	Gas (trillion cu ft)
INTERMEDIATE BOILERS					
Watertube ≤500,000 pph	1,838	132	194	14	1.72
Firetube	813	11	98	69	1.12
Cast Iron	757	11	56	37	1.03
TOTAL*	3,370	154	348	120	3.87
ALL BOILERS					
Residential	2,117	---	---	355	3.15
Commercial	1,341	26	106	58	1.33
Industrial	1,515	84	192	60	1.99
Utilities	1,800	271	156	2	2.76
TOTAL	6,733	381	454	475	9.23

---

*Totals do not necessarily add up due to rounding.

TABLE 1-2

REGIONAL DISTRIBUTION OF INTERMEDIATE BOILERS

	Capacity (million pph)	% of Total	Coal (million tons)	Residual Oil (million bbls)	Distillate Oil (million bbls)	Gas (trillion cu ft)
Atlantic	913	27.1	40	202	74	.26
Great Lakes	818	24.3	62	42	26	.76
Far West and South	770	22.8	2	60	5	1.73
Central Urban	399	11.8	17	11	3	.72
South East	362	10.7	26	17	5	.32
Rural North	108	3.2	7	16	7	.08
TOTAL INTERMEDIATE BOILERS	3,370		154	348	120	3.87

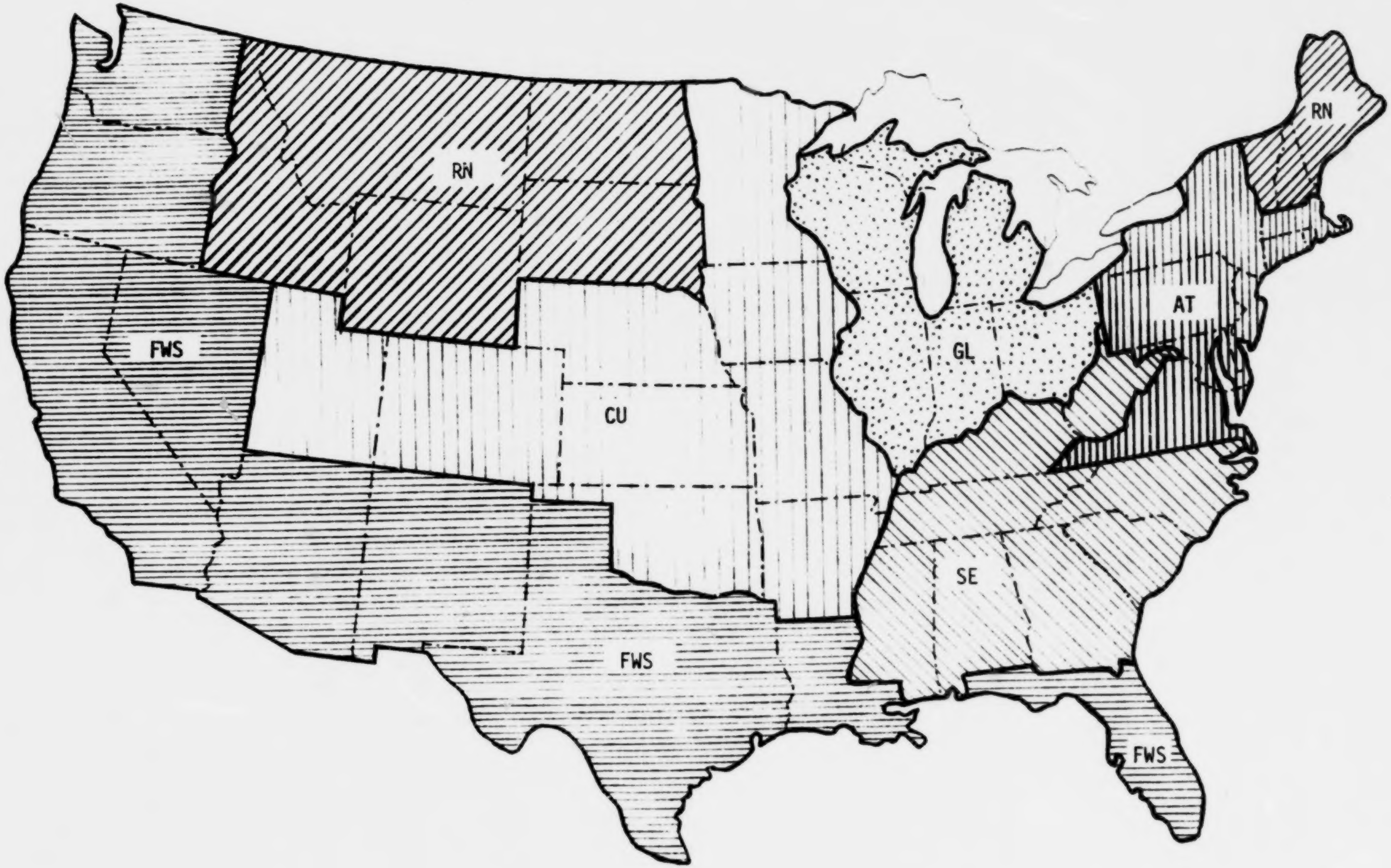

RN
RN
AT
GL
CU
SE
FWS
FWS
FWS

Figure 1-1. Regional Boundaries

boilers. The large percent of equipment capacity in these regions corresponds to the population, age, and industrial characteristics of these areas relative to the country as a whole.

iii. A little over half of this 1967 capacity consists of watertube boilers and the other half is more or less equally distributed over firetube and cast iron units.

iv. Although detailed data are not available in this study on residential and large utility boilers, it is noted that of the total 1967 boiler capacity the residential capacity is the largest class of equipment, followed in order by utility, industrial, and commercial units. The contribution to air pollution by residential users can be shown to be, however, of least importance among the equipment studied. This is due to the dominance of the use of "cleaner" fuels, i.e., gas and distillate oil, and to low load factor (equivalent to the percent of time the equipment operates at rated load).

b. Emissions

Table 1-3 summarizes the emission results by boiler type and user for 1967.

Table 1-4 presents the regional distribution of the emissions from intermediate-size equipment only.

The significant features of the 1967 emission estimates are summarized below.

(1) General. The data generated in this study are based on annualized average operating factors and on uniform, average data for each region considered. This limitation, which was imposed by the methodology used to build up the inventory, tends to downplay the importance of emissions from intermediate-size boilers relative to all stationary sources. First, a major portion of intermediate boilers is used for space heating, which exhibits large seasonal fluctuations. Second, these sources tend to be located centrally in urban and metropolitan areas, and

TABLE 1-3

1967 EMISSIONS SUMMARY
(in million tons)

	SO_2	NO_x	Controlled Particulates
INTERMEDIATE BOILERS			
Watertube boilers ≤500,000 pph	6.93	1.54	3.83
Firetube boilers	.88	.24	.29
Cast iron boilers	.73	.15	.27
TOTAL	8.54	1.93	4.39
ALL BOILERS			
Residential	.24	.23	.09
Commercial	1.52	.36	.77
Industrial	4.27	1.04	2.39
Utilities	15.17	3.40	2.03
TOTAL	21.20	5.03	5.28

TABLE 1-4

1967 EMISSIONS FROM INTERMEDIATE BOILERS BY REGION

(emissions in 10^6 tons per year)

	SO_2 (emissions)	%*	NO_x (emissions)	%	Controlled Particulates (emissions)	%
Great Lakes	3.4	40.0	.60	31.1	1.75	39.9
Atlantic	2.5	29.4	.56	29.0	1.23	28.0
South East	1.0	11.8	.24	12.4	.62	14.1
Central Urban	.9	10.6	.21	10.9	.54	12.3
Far West and South	.4	4.7	.24	12.4	.06	1.4
Rural North	.3	3.5	.08	4.2	.19	4.3
TOTAL	8.5		1.93		4.39	

---

*Percent of National Total for each pollutant to release stack gases at low heights. Thirdly, over half of the emissions of all three pollutants is produced in the Great Lakes and Atlantic regions, where the above two factors are most significant - the areas are well developed and highly centralized, and located in the northerly part of the country.

It is difficult to quantify these effects; in evaluating the overall, averaged results and conclusions of this study, the reader should, however, keep these factors in mind. The relative seriousness of any potential pollution burden, because of the regional characteristics, will be greater in the Great Lakes and Atlantic region so that any timetable for control development and implementation regarding intermediate stationary sources should certainly place priorities on those regions.

(2) Particulate Emissions. Particulate emissions from intermediate sources, as estimated in this study, are about 80% of the total particulate emissions from stationary sources, considering present installed controls. Any immediate reduction in particulate emissions from stationary sources must come from imposing control measures on intermediate-size equipment, whereas further improvement of control equipment for large size utilities can only produce incremental results.

(3) SO_2. The total national emissions of SO_2 from intermediate sources represent about 40% of the total emissions from all stationary sources, based on Walden's results. On this basis above, the major large industrial and utility sources merit the highest priority of attention. Considering the weighting that may be given to intermediate boilers by the factors above, and noting that almost 70% of the national total is in the Great Lakes and Atlantic, the intermediate sources of SO_2 appear to merit substantial consideration in setting priorities for control.

The whole problem is being alleviated by current control approaches emphasizing use of low sulfur fuel and flue gas treatment on large utility plants. The imposition of these strategies will increase the relative importance of intermediate sources (while reducing the absolute total level of emissions).

(4) $\underline{NO_x}$. Intermediate boilers contribute approximately 20% of NO_x emissions of all stationary sources, and about 12% of all NO_x including transportation (based on Walden and Esso estimates [1-1]).* Accordingly, this source class does not appear to represent the significant set of emitters and should be ranked as such in setting priorities. Although the largest stationary contributor source class is utilities [1-1], the effect of plant location and stack height on the relative importance of emissions from intermediate-size sources may be significant. Further examination of these factors is needed to provide clarification.

(5) Combined Pollutant Burden. It will be shown that it is important to consider simultaneous controls for the three major emissions from stationary sources rather than looking at each one as a distinct and separate problem. Figure 1-2 shows the relative contribution to the combined emission of NO_x, SO_2 and particulate of each major equipment class further distributed by fuel. The combined totals were obtained by summing percent of contribution (not annual emission in tons). The important and obvious feature is the substantial predominance of coal-fired watertube boilers in the intermediate-size range.

C. PROJECTIONS OF BOILER CAPACITY, FUEL USE, AND EMISSIONS

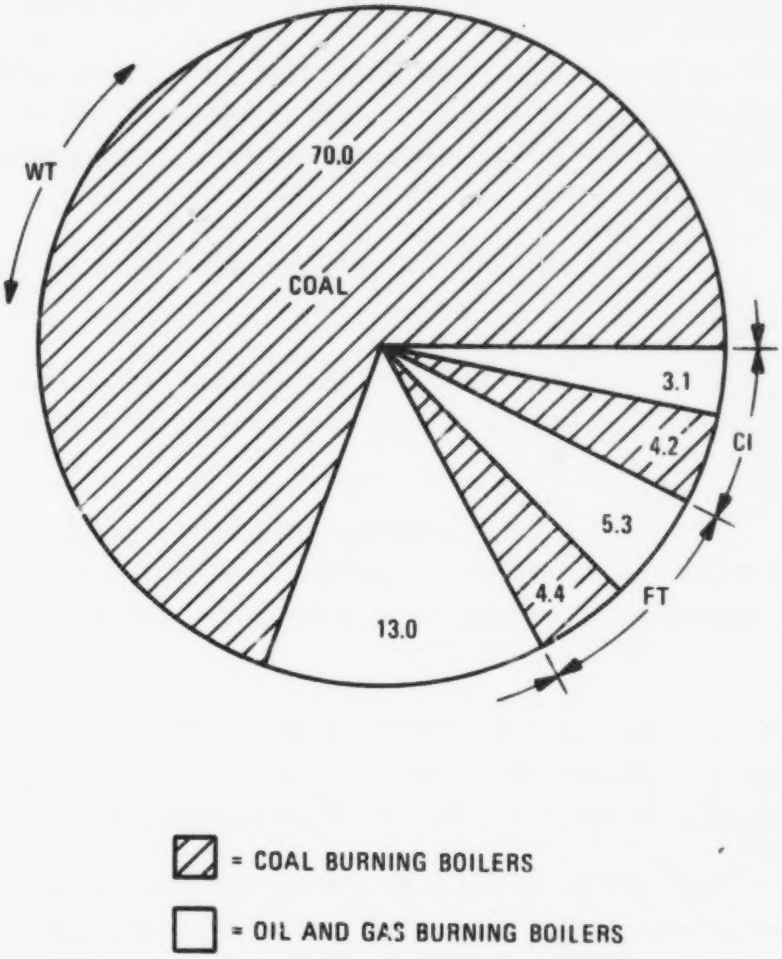
1. Definitions, Assumptions, and Bases

The results of the projections in this study depend strongly on the assumptions described below. The projections were based on past trends and reflect the demands for the equipment and fuel involved, with little emphasis placed on supply functions.

a. Projections were based on correlations between boiler sales and economic indicators, such as gross national product, derived by applying stepwise regression analysis to historical data.

---

*Numbers in square brackets refer to bibliographic citations listed at the end of each section.



NOTE: VALUES IN PERCENT OF TOTAL

Figure 1-2. Combined Emissions (1967) from Intermediate Boilers - By Type and Fuel.

b. Future values for the economic indicators were obtained by means of linear regression over time. This approach removes all cyclical components from the model, a limitation which is of little significance in this study, which was concerned only with projections over five-year periods and not short-term year-by-year projections.

c. Qualitative judgment was superposed on the projection results where it appeared that trends had changed drastically in the past few years, making certain periods of sales of less importance to the future trends.

d. Actual sales data were used, where available, instead of projected figures, i.e., for 1968 and 1969.

e. Retirements based on the estimated life-span of the various boiler types were calculated on a first-in-first-out basis, using sales figures.

f. Percentage of watertube sales in the greater than 500,000 pph size segment as well as user distribution of the projected boiler inventories were estimated by means of recent trends and socio-economic factors.

g. Regional distribution of the projected boiler inventories were based on socio-economic factors, for which projections were obtained from the Bureau of Census and National Planning Association.

h. Fuel distribution of the projected boiler inventories were based on region-by-region linear fuel projections, adjusted to reflect the resistance build-up due to saturation, limited supply, and higher costs of other fuels.

i. Assumed emission control values were incorporated to reflect a continued increase in particulate control. SO_2 and NO_x emissions were projected both on an uncontrolled basis and assuming controls on large utility boilers.

j. No analysis was made of the fuel supply problems. Except for ad hoc adjustments to growth rate for gas consumption and rate of decline of coal consumption (where the projections appeared unreasonable), the projections rely on unlimited fuel supplied for all major fossil fuels considered here.

k. No provision was made to project the encroachment of nuclear energy on conventional energy. It should be pointed out that this factor would solely affect the sales of large utility boilers which were not included in this study. This factor has a significant effect on fuel supply, however,

(1) No changes in operating factors such as boiler efficiency, load factor, fuel sulfur content, were assumed in the projections.

2. Projections

a. Capacity and Fuel Use

Projected capacity of intermediate-size and total boilers is shown in Table 1-5. Corresponding fuel use is shown in Table 1-6. The significant features of these projections are:

i. By 1990, the combined capacity of the intermediate-size boilers will be almost equal to the total present (1967) capacity.

ii. Firetube boilers will largely displace smaller watertube boilers, unit for unit up to about 600 boiler horsepower and in larger installations with up to six firetube units operating together.

iii. Total watertube capacity including the large (size 4) utility units will grow rapidly in the future.

iv. Fuel use in the intermediate-size boilers will shift further from coal today to gas and oil by 1990. This projection is

TABLE 1-5

CAPACITY OF BOILERS BY TYPE AND USER

(output rating in 10^6 pph)

	1967	1975	1980	1985	1990
BY TYPE					
Total Watertube	3,086	4,595	5,686	6,950	8,379
Size 1 - Under 100,000 pph	921	1,045	1,123	1,201	1,275
Size 2 - 100,001-250,000 pph	658	700	745	810	898
Size 3 - 250,001-500,000 pph	259	286	282	276	262
Size 4 - Over 500,000 pph	1,248	2,564	3,537	4,663	5,944
Firetube	813	1,365	1,783	2,255	2,650
Cast Iron	757	985	1,098	1,330	1,461
Residential	2,117	2,877	3,359	3,844	4,344
TOTAL BOILERS	6,773	9,822	11,927	14,379	16,834
*Intermediate Size Boilers	3,370	4,335	5,030	5,838	6,602
BY USER - TOTAL BOILERS					
Commercial	1,341	1,857	2,192	2,578	2,964
Industrial	1,515	1,989	2,333	2,770	3,188
Utility	1,800	3,099	4,043	5,187	6,338
Residential	2,117	2,877	3,359	3,844	4,344

---

*Totals do not necessarily add up due to rounding.

TABLE 1-6

PROJECTED FUEL USE (QUANTITY UNITS) - U.S. TOTALS

	Fuel Consumption				
	1967	1975	1980	1985	1990
TOTAL BOILERS					
Coal (million tons)	381	567	785	913	1,107
Distillate Oil (million bbls)	475	640	761	835	1,021
Residual Oil (million bbls)	454	732	894	1,083	1,237
Gas (trillion cu ft)	9.23	15.20	17.55	23.72	28.14
INTERMEDIATE SIZE					
Coal (million tons)	154	111	104	94	81
Distillate Oil (million bbls)	120	204	245	283	366
Residual Oil (million bbls)	348	510	579	664	750
Gas (trillion cu ft)	3.87	6.77	8.42	10.40	12.12

based on the above-mentioned assumptions of linear trend extrapolation and does not reflect potential supply limitations. The emissions projections, shown immediately below, are highly sensitive to these assumed fuel trends so that uncertainties in future supply/demand relationships must be considered carefully. Capacity growth and interchange among the different boiler types, while also based on trend extrapolation, does not appear quite as sensitive to the same kind of economic uncertainty.

b. Emissions

Projected emissions of SO_2, NO_x and particulates are shown in Table 1-7. SO_2, NO_x and uncontrolled particulate projections assume no controls on any boilers. Controlled particulate projections are based on continuation of present control practices on all boilers, but not on the implementation of any new control regulations.

On this basis, and, with the assumed fuel trends, both the controlled particulates and SO_2 emissions will decrease through 1990, while NO_x will show a slight increase. This follows the substitution of gas (almost four-fold increase) and distillate oil, both relatively clean fuels, for the dirtier fuels, residual oil (two-fold increase) and coal (nearly halved). It is not likely that any demand limitations will cause this shift to move further toward the clean fuels in the future; rather, possible shortages of gas and oil are more likely. The consequences are that the projection in Table 1-7 should be conservative. It is significant that the overall fuel consumption in 1990 in intermediate boilers will be nearly as large as the consumption of all boilers (including residential and large utility units) in 1967, so that there exists the potential danger of severe pollutant burdens (of the order of current problems) from this source group, if the fuel trends predicted do not materialize.

Examination of Table 1-7 indicates that intermediate-size sources are relatively small compared to the total boiler output and tend to become even smaller relatively with time. This behavior as explained above appears to be due to the almost exponential utility

TABLE 1-7

EMISSION ESTIMATES - TOTAL U.S. FOSSIL FUEL FIRED BOILERS

	1967	1975	1980	1985	1990
SO_2 (10^6 tons/year)					
All	21.20	36.00	46.31	58.19	70.63
Intermediate	8.53	7.63	7.70	7.67	7.56
NO_x (10^6 tons/year)					
All	5.03	8.55	11.03	14.00	17.08
Intermediate	1.94	2.08	2.25	2.44	2.63
Particulate (controlled) (10^6 tons/year)					
All	5.28	3.76	4.22	3.88	4.24
Intermediate	4.38	2.53	2.46	2.06	1.90
Particulate (uncontrolled) (10^6 tons/year)					
All	25.71	45.68	59.83	76.28	93.52
Intermediate	7.99	6.10	5.86	5.56	5.19

capacity growth compared to the more or less linear industrial/commercial growth and to the changing fuel use patterns. This does not, however, reflect the relative significance of emissions considering likely control practices. It is expected that SO_2 emissions from large boilers, especially utility boilers, will be controlled significantly in the future either by imposition of sulfur in fuel restrictions or through application of flue gas treatment procedures, resulting in a larger share of the emissions coming from intermediate sources as shown in Figure 1-3. Note that prior to 1990, intermediate source emissions will, under these assumptions, become more significant than the emissions from large boilers. The above comparison was based on the following assumed levels of control for large utility boilers (size WT-4).

	1967	1975	1980	1985	1990
Control Strategy A	0%	63.6%	75%	83%	90%
Control Strategy B	0%	63.6%	80%	90%	95%

For both cases A and B the percentage control assumed by 1975 was as reported in The Cost of Clean Air [1-2], a report of the Secretary of HEW to Congress. For case A, a slower adoption of SO_2 control was assumed than for case B.

Similar estimates were made for future NO_x control possibilities (Figure 1-4). Although intermediate sources are not expected to emit more NO_x in the future than controlled large sources would, their share in NO_x emissions remains substantial. The percentages of control assumed were 30, 40, 45, and 50 percent for 1975, 1980, 1985, and 1990, respectively [1-1].

Whereas controls have not been employed historically for SO_2 and NO_x, particulate emissions have been controlled by a variety of means for many years. These controls have been used more widely on large installations, so that the present relative emissions from intermediate-size boilers are estimated to be a significant part, about 83%, of the

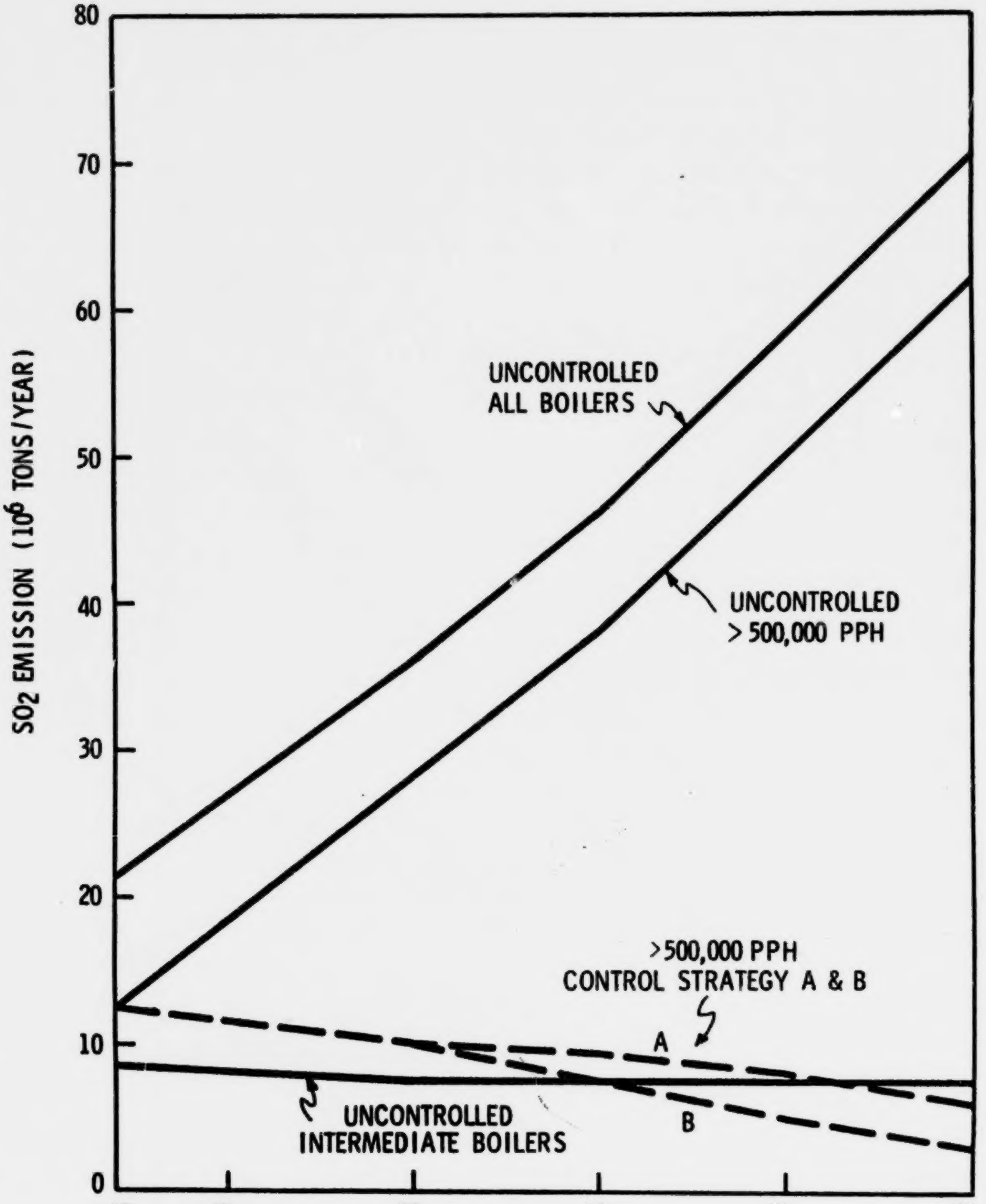


Figure 1-3. Effect of Projected Control Levels on SO_2 Emissions.

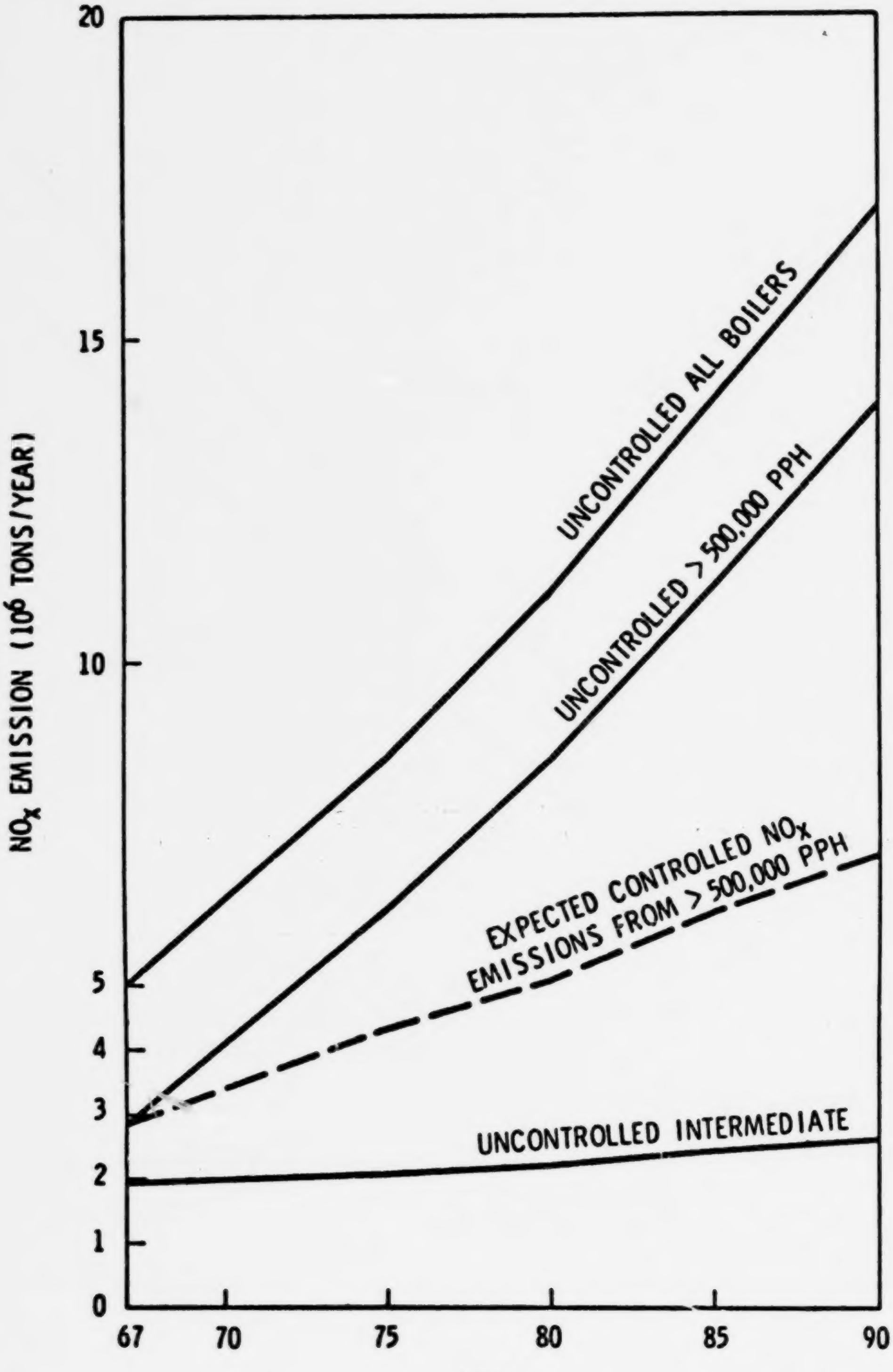


Figure 1-4. Effect of Projected Control Levels on NO$_x$ Emissions.

total emission. Assuming a continuing trend of levels of particulate control equipment on large boilers, intermediate particulate emissions remain a significant part, about half by 1990, of the total particulate emissions.

Considering that controls for large stationary combustion sources, both presently available and under development, are pushing the state-of-the-art in efficiency, it appears necessary to look at the intermediate-size range to obtain abatement of SO_2 and particulates beyond that expected from applications of large-scale control technology. For example, little further decrease in particulate emissions can be expected by requiring better controls on utility plants in the future where controls already exceed 99% efficiency. Reduction in levels will require control of intermediate sources.

Regional considerations indicate that the Great Lakes and Atlantic Regions require priority attention in the present time frame. Problems in the fast-developing regions, Far West and South, and Southeast appear later. The Far West and South are the fastest growing areas in the country. Pollution burdens from stationary sources in that region are minimized, however, by the widespread use and availability of natural gas; almost no coal is now used or is projected for use. The Central Urban and Rural North with relatively low population density, lower urbanization and industrial development exhibit the least pollution burden presently and also in the future projections.

D. CONTROL STRATEGIES

The analysis of control of emissions from intermediate-size boilers was approached in terms of strategies for both control of the separate three pollutants and also in terms of combined emissions. The principal control approaches examined were:

1. Fuel Switching
2. Flue Gas Treatment (FGT)
   Particulate Collectors

SO_2 Removal Systems
NO_x Removal Systems

3. Combustion Design

Fuel Additives
Combustion Modification and Control

  Low Excess Air (LEA)
  Flue Gas Recirculation (FGR)

1. Description of Strategies

a. Fuel Switching

Fuel switching consists of the substitution of the cleaner fuels for more polluting fuels in the general ranking:

gas
distillate oil
low-sulfur residual oil
high-sulfur residual oil
coal

The feasibility and benefits of fuel switching depend on the availability and cost of the fuel which, in turn, is sensitive to location; and on the relative emission factors for each fuel type. Fuel switching evaluation in this study was based on several key assumptions:

i. No restrictions on supply were considered.
ii. 1967 price structure was used.
iii. Average emission factors were used in preparing the estimates.

The costs of fuel switching include both additional fuel costs and annualized capital costs associated with conversions from one fuel to another.

b. Flue Gas Treatment

(1) Particulate Collectors. Collection systems applicable to intermediate-size equipment are available within the present state-of-the-art. The classes of collectors examined and design efficiency for coal particulate included:

Class	Design Efficiency
Dry Inertial (cyclone)	94%
Wet Scrubbers - high pressure drop (Venturi)	98%
Wet Scrubbers - low pressure drop (all others)	94%
Electrostatic Precipitators	99.5%
Fabric Filters	99.5%

Design and cost data were extracted from existing sources. The particulate collection efficiency in alkaline scrubbers for combined SO_2/NO_x/particulate removal was assumed to be 96%.

(2) SO_2 Removal Systems. A review of all potential processes for SO_2 removal was made. Elimination of many approaches applicable only to large-scale units (50 MW or larger) was made. Further, only processes which were non-regenerative (throwaway), or could be part of a centralized, regional regeneration-recovery system were examined. Little or no operating, design, or cost data were available on the application of any of the processes to intermediate-size units.

A further elimination resulted in the selection of the following SO_2 removal schemes which appear most practical for this broad class of equipment; for these, engineering design and cost data were developed for each of the separate boiler types and sizes. The SO_2 removal design efficiency for each approach is also given.

Process	Efficiency
Sodium carbonate, dry, added to flue gas after boiler, dry collector	60%
Sodium carbonate, in solution, added to scrubber	95%
Calcium oxide, slurry, added to scrubber	90%
Calcium carbonate, slurry, added to scrubber	50%
Calcium carbonate, dry, added to furnace, dry collector	40%
Calcium carbonate, dry, added to furnace and scrubber	90%

(3) NO_x Removal Systems. No flue gas treatment process was considered far enough advanced in development to be examined in detail for application to intermediate boilers. The relative contribution of all intermediate boilers to total NO_x emissions is small, so that schemes capable of removing only NO_x appear to be of limited usefulness for intermediate boilers. Processes which remove NO_x simultaneously with SO_2 are, on the other hand, of potential merit, if their application can be justified on the basis of the need to reduce the SO_2 portion. The TYCO approach, based on the lead chamber sulfuric acid process, fits this characteristic, but, at the same time, appears too complex from an operating point of view for application to intermediate-size equipment. Insufficient data were available for a quantitative analysis in the cost-effectiveness phase. Alkaline scrubbers are reported to remove a portion of the nitrogen oxides. In examining the combined effectiveness of scrubbers, removal of 20% of the oxides was assumed.

c. Combustion Modification

This category is very broad in coverage encompassing combustion theory and its effect on equipment design such as specific heat release, flame temperature, residence time of gases in furnace, instrumentation, excess air quantities, fuel additives, flue gas recirculation, furnace geometry, two-stage combustion, mechanics of fuel-air mixing and others. In terms of potential improvement in emissions, these design parameters can have almost no effect on SO_2 emissions from a given fuel, a relatively small effect on particulate emissions, except possibly for oil-fired units, but potentially substantial effect on NO_x emissions.

Of all the above, it is believed that only low excess air and flue gas recirculation, or both in combination, are presently applicable to intermediate-size boilers from the standpoint of available technology and state-of-the-art. The others exist in various stages of theoretical consideration, laboratory development, and pilot operations. Based on the Esso NO_x study [1-1] and on reported installations in this country and abroad, it is projected that all sizes and types of intermediate boilers on oil and gas firing can realize meaningful reductions of NO_x emissions. An especially attractive feature of present (and probably most potential) combustion modification strategies is the fact that, as improvements, they involve a low level of capital expenditure; further, some of them hold the potential of operating cost savings of an amount equal to or even greater than the annualized capital cost.

One potential limitation in combustion modification approaches may arise from the relation of fuel nitrogen to nitric oxide in the combustion products. If, as is indicated from some present work, this nitrogen substantially appears as nitric oxide in the gases, then the potential efficacy of the modification approaches may not be sufficient to achieve, on an absolute basis, the low concentrations required by emission standards or, to reduce levels economically, relative to other approaches.

Fuel additives, listed as a modification in the first paragraph, refer more specifically to application in liquid fuels. Much work has been done by manufacturers in development and marketing; only recently has there been any beginning of objective determination of the efficacy of additives. The potential exists for such a strategy to be useful in reducing emissions of particulates, SO_3, and NO_x, but at present only incremental improvements can be foreseen, much less presently realized. Most present investigation and commercial marketing is directed at the SO_3 problem (which, as an individual emission, is not treated in this study) and at particulates from distillate fuel oil. Much past work on additives has been principally directed to the elimination of fouling and corrosion of heat transfer surfaces, reduced emissions being only an incidental side effect.

2. Applicability of Strategies

The applicability of the various control approaches to the various equipment classes was determined before the detailed cost-effectiveness analysis. Fuel switching was examined in various combinations and permutations in relation to all equipment. Prescreening of the applications of particulate collectors eliminated fabric filters and electrostatic precipitators on economic bases. Dry mechanical collectors were considered for coal-burning units of all sizes and types. Wet scrubbers were not considered applicable independently as particulate collectors but were examined in conjunction with SO_2 and NO_x removal. No particulate collectors were considered for gas and oil-fired units.

Wet scrubbing, flue gas treatment approaches for SO_2 control alone or for combined pollutant removal were examined only for watertube boilers. Only simple alkaline scrubbing was considered as practically feasible for intermediate-sized units. Further, operating problems, space needs, general lack of acceptability by owner/users were considered sufficiently negative reasons to eliminate this approach for firetube and cast iron boilers. As noted, flue gas treatment for NO_x removal alone was eliminated on the basis of inadequate development and demonstration of feasibility.

Combustion modification approaches were examined, vis a vis, all sizes and types of units. No prescreening was made. The limitations in application of this approach noted below arose out of the cost effectiveness analyses, not from an a priori elimination.

3. Cost-Effectiveness

The cost effectiveness of a variety of strategies based on combinations of the above control approaches were examined. The measure of effectiveness for the individual pollutants was expressed in terms of annual cost versus quantity removed. Strategies for controlling more than one pollutant simultaneously were compared on the basis of cost to accomplish equivalent reductions in emissions.

Fuel switching emerged as the most effective strategy. The principal contributors to the combined pollutant burden from intermediate boilers are coal-burning units. Details of a strategy switching all coal-burning units to oil or gas and switching present residual oil to low-sulfur residual oil, depending on the region, are shown in Table 1-8. The effect on reducing pollutant emissions is shown in Figure 1-5 and Table 1-9. Other combinations of switching were considered. The strategy detailed appears to be the most cost effective, although switching to all gas in all regions will further reduce the emissions. There are many areas in which this does not appear to be practical from the standpoint of supply and logistics.

This strategy was compared to the other alternatives using the technological control approaches. The best appears to be alkaline scrubbing, which approach approximates fuel switching in its combined effect on the simultaneous removal of all these pollutions. Using 1967 prices, the annual costs of that approach are significantly higher than fuel switching as shown in Figure 1-6. Not until fuel prices rise to a level nearly two times higher than the 1967 index will this alternative appear to be equally competitive, as shown also in Figure 1-6.

The initial capital costs of flue gas treatment are much higher as shown in Table 1-10. The costs in the table indicate that even the best control strategy is expensive in terms of capital requirements. The relative effectiveness of fuel switching depends on the price of fuel, which, in turn, depends on its availability. No models

TABLE 1-8

DISTRIBUTION OF UNITS IN FUEL SWITCHING STRATEGY

(Entries are number of units switched)

Region	Class	Switch Coal to Gas	Switch Coal to DO	Switch Coal to Lo-S	Switch RO to Lo-S
AT	WT-1			2460	4705
	WT-2			372	707
	WT-3			116	40
	FT		2815		45700
	CI		14400		241800
GL	WT-1	3405			513
	WT-2	646			97
	WT-3	207			0
	FT	7580			8440
	CI	36800			40000
WS	WT-1	135			783
	WT-2	12			85
	WT-3	15			58
	FT	1297			6930
	CI	8000			54600
CU	WT-1	567			378
	WT-2	73			49
	WT-3	51			69
	FT	2165			1729
	CI	11200			9590
SE	WT-1			1322	351
	WT-2			287	73
	WT-3			87	0
	FT		4760		2380
	CI		24000		11180
RN	WT-1	27			243
	WT-2	6			30
	WT-3	33			4
	FT	648			1082
	CI	3200			6400
Totals	WT-1	4134		3782	6973
	WT-2	737		659	1041
	WT-3	306		203	171
	FT	11690	7575		66261
	CI	59200	38400		363570
Totals	ALL	76067	45975	4644	438016

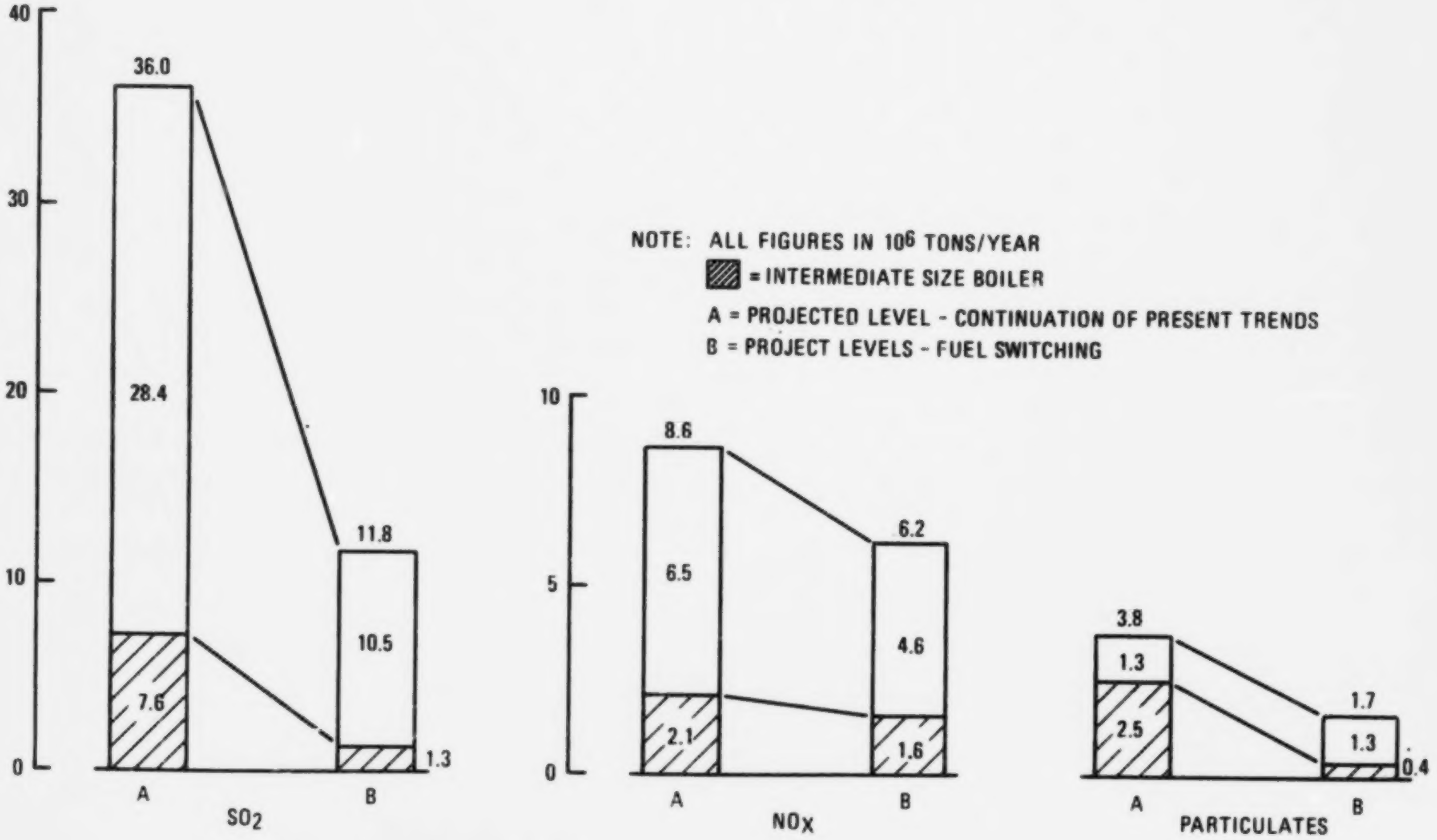


Figure 1-5. Projected Reduction in 1975 Emission Levels from Fuel Switching.

TABLE 1-9

ALTERNATIVE STRATEGIES FOR INTERMEDIATE BOILERS

	SO_2		NO_x		Particulate	
	Emissions (10^6 T/Y)	% Reduction	Emissions (10^6 T/Y)	% Reduction	Emissions (10^6 T/Y)	% Reduction
1975 Projected Base Levels	7.63	----	2.08	----	2.53	----
Fuel Switching (Table 1-8)	1.28	83.3	1.62	22.2	0.40	84.3
Flue Gas Treatment (Watertube Only)	2.58	66.0	1.78	14.5	0.63	75.5

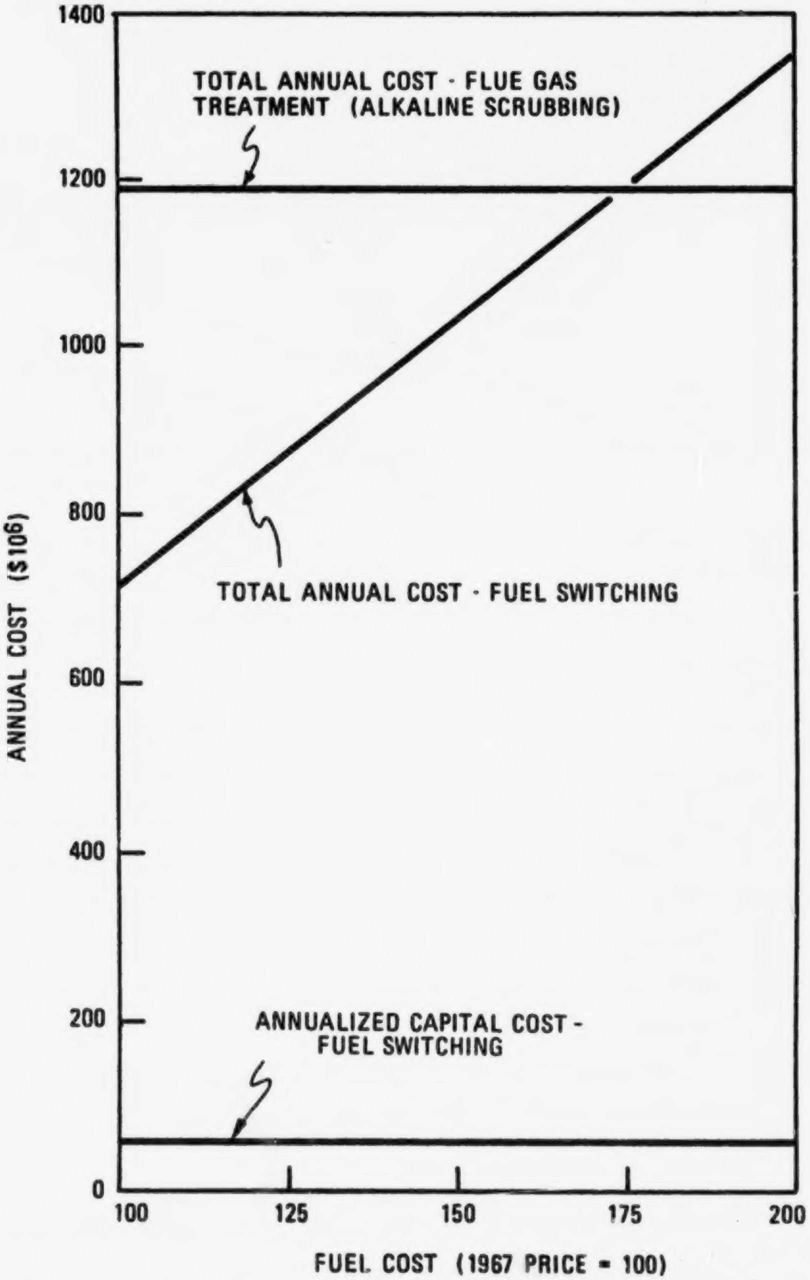


Figure 1-6. Cost Comparison of Alternate Strategies for Watertube Boilers.

TABLE 1-10

COST OF STRATEGIES - WT BOILERS ONLY

		Initial Capital Costs	% of Boiler Costs (Replacement Basis)
Fuel Switching	WT only	$ 438 x 10^6	13
	FT and CI	459 x 10^6	59
Alkaline Scrubbing	WT only	$1485 x 10^6	45

for availability were introduced in the cost effectiveness analysis. Alternatively, means to assure the availability on essentially the same interfuel competition basis as exists presently were examined. The means are coal conversion to gas and liquid forms, and the implementation of a national fuel policy restricting the use of the "clean" fuels to intermediate (and residential) installations.

Application of combustion additives to oil-burning in combination with fuel switching appears to provide additional pollutant reduction with little additional costs (no capital investment). Combustion modification (watertube boilers only) to reduce NO_x emissions also appears to provide additional abatement in combination with fuel switching, and, if the potential operating efficiencies are achieved, can result in savings. The capital cost of applying this strategy to existing cast iron and firetube boilers is staggering. Neither of these approaches offers sufficient reduction of the combined emissions, independent of fuel switching, to merit large development programs and should be viewed as an adjunct to fuel switching.

The above results depend on the assumption of adequate future supply of gas and oil at a reasonable price. Other approaches should be examined and developed to provide a reasonable alternative. Such approaches should be able to reduce emissions of all three pollutants simultaneously. New combustion processes, alkaline scrubbing, and solid sorbents for flue gas treatment appear to offer potential as alternatives.

E. RECOMMENDATIONS

Examination of the results of the development of the emission estimates and projections, and of the analysis of control strategies, point to three principal sets of recommendations:

(1) Improvements on the present study
(2) Implementation of fuel switching
(3) Development of alternative approaches

1. Improvements of the Present Study

The first set reflects uncertainties and limitations resulting from assumptions, idealizations, and imperfect data inputs inherent in the analytic procedures employed in the study. Quantitative considerations of seasonal factors, source location and stack height should be introduced in assessing the significance of emissions. A combined index of emissions is needed to assess the total problem. The study should be updated and checked against actual future developments. More fine structure should be introduced.

The fuel switching analysis depends on several key assumptions regarding fuel price and availability. Re-examination considering supply/price forecasts should be made. Substitution of utility-generated pipeline steam or electric heat for intramural steam raising is an alternative to fuel switching that merits evaluation. The technology and economics of centralized regenerative flue gas treatment approaches need further study. The impact of the new proposed national emission standards should be examined.

In view of the above considerations, the following topics should be examined in order to improve on and enlarge the significance of the present study.

Improvements on Present Study

- Re-examine emission levels considering

  - seasonal fluctuations
  - stack height
  - source location

- Refine regional structure
- Examine sensitivity of results to assumptions and error in inputs
- Update inventory and emission estimates
- Use more realistic operating factors
  - load factor as function of user
  - effect of transients on emission factor
  - effects of age, operator competence, equipment condition
- Refine fuel switching analysis
  - supply/demand limitations
  - price projections
  - substitution of nuclear power
- Use discount rate (annualizing factor) depending on user
- Develop better combined measures of effectiveness
- Examine alternative means for providing space heating and process steam for intermediate-size users
  - electric heat
  - for core city demand, supply from utility, incinerator or centralized low-pressure steam plant
- Examine regional, centralized flue gas treatment
  - logistics
  - costs
  - process selection
- Examine impact of absolute emission standards

2. Implementation of Fuel Switching

Fuel switching is shown to be the preferred control strategy for intermediate boilers so long as fuel prices do not increase beyond the crossover point at which combined flue gas treatment becomes competitive. Examining recent trends in price, particularly for low sulfur residual oil, now in high demand, it might appear that that point would be reached in the near future. Because fuel switching has many attractive features other than low annual operating costs -- such as low capital cost, minimum operator attendance and retraining, low maintenance -- it is important to seek means to maintain the price of fuel and the adequacy of supply at levels where this strategy remains effective.

One such approach is the development and implementation of a national fuel or energy policy which allocates fuels among major users according to some environmental and economic constraints. An alternative to such a fuel allocation policy is the development of processes to convert the dirty fuels, coal or high-sulfur residual oil, into clean fuels.

Associated with fuel switching as a broad strategy are two technological means to complement that strategy and achieve further reduction in pollutant levels. Employment of combustion additives can, in principle, reduce the total pollutant burden on top of the gains accomplished by switching. Likewise, combustion modification offers a demonstrated means to reduce NO_x emissions beyond the basic reduction from fuel switching.

In view of these considerations, the following topics should be examined as part of a program to implement fuel switching as a control means for intermediate-size boilers.

Implementation of Fuel Switching

- Fuel availability assurance
  - develop national fuel use policy
  - develop coal conversion technology

- Combustion additives R&D
    - theoretical studies
    - pilot and full-scale testing
- Combustion modification R&D
    - combustion modeling
    - effects of fuel nitrogen - limitation to modification approaches
    - demonstration of intermediate-size applications of LEA, FGR, TSC
    - combustion control improvement
    - reduction of emissions by controlling time, temperature, excess air, fuel flow cycles
    - burners for LEA oil burning

3. Alternative Approaches

It was noted that fuel-switching is the better strategy up to some point when fuel costs become so high that the economics support flue gas treatment as a more effective alternative. Although there appear to be approaches (above) to lessen the probability of this occurrence, it appears desirable to support a program in flue gas treatment as a back-up measure. Both economic and practical factors show that such processes should be capable of simultaneously removing most (above 80%) of the particulates and sulfur oxides, and at least 20% of the nitric oxides.

Alkaline scrubbing schemes have potential to achieve that overall level of performance, but have not been commercially developed for application to intermediate-size systems. Regenerative/recovery schemes appear practical only in a centralized basis. Fixed bed, replaceable sorbent units show some promise in application to smaller units, however, very little design or theoretical data exists on the performance or cost of such systems.

New combustion processes, in which emissions are reduced by changes in the combustion regime or are removed in situ bear promise as still another alternative to fuel switching.

Summarizing the alternatives to fuel switching, it is recommended that the following topics be examined:

Alternative Approaches

- Develop intermediate-scale alkaline scrubbing processes
  - laboratory scale research - thermodynamics, kinetics
  - combined removal - SO_2, NO_x, particulates
  - optimize combined effectiveness
  - centralized regenerative process development
  - design and demonstration of unattended systems
- Solid sorbents for flue gas treatment
- New combustion processes
  - fluid bed combustion

REFERENCES TO SECTION I

1-1. Bartok, et al., "Systems Study of NO_x Control Methods for Stationary Sources," Esso R&D Co. (NAPCA Contract PH 22-68-55), November 1969.

1-2. "Cost of Clean Air," First Report of the Secretary of Health, Education and Welfare to the Congress of the United States on the Air Quality Act of 1967, June 1969.

II. INTRODUCTION

This report describes the results, methodology and data base for a study of air pollution from stationary intermediate-size fossil-fuel burning combustion equipment and of its control. This work has been carried out under Contract No. CPA 22-69-85, sponsored by the Air Pollution Control Office (APCO) of the Environmental Protection Agency.

The purpose of this systems study was:

(1) to define the contribution to air pollution by intermediate-size fossil-fuel combustion equipment

(2) to evaluate the need for air pollution control and the cost effectiveness of available control methods for the major intermediate-size sources, and

(3) to develop the research and development program necessary to provide effective, economical control of such sources.

The work was divided into the five following phases:

I Identification of Equipment Types and Fuel Usage

II Determination of Major Emission Sources

III Definition and Projections of Air Pollution from Intermediate Sources

IV Techno-Economic Evaluation of Air Pollution Control

V Research and Development Program Planning

A major part of the study was the identification of pollutant sources according to equipment type and size, regional distribution, fuel, user, age and other significant factors. It is important to note the several definitions that have been employed. Comparison of the results of this work with that contained in others is inevitable, and it is important that only equivalent sources groupings be compared. This study was limited to:

(1) Intermediate-size equipment and

(2) Conventional boilers

The definition of conventional boilers adopted denotes fossil-fuel burning stationary combustion equipment in which the flue gases are not altered by the addition of non-combustion products. With this definition, process equipment such as metallurgical furnaces, coke ovens, glass and ceramic furnaces and kilns, cement and lime kilns, and drying ovens of all varieties is excluded. Equipment in which bark, bagasse or other waste materials is used as fuel and incinerators of conventional design are excluded by the fossil-fuel constraint which limits the fuel used to gas, residual or distillate fuel oil, and coal. This definition was adopted in order to introduce commonality into the control strategy evaluation phases. In many of the excluded types of equipment, non-combustion emissions are the dominant parts, and control measures would be dictated by that aspect, not the combustion-derived portion.

The term conventional boiler has been taken to include all steam-raising equipment, and hot water heaters and hot-air furnaces used for space heating (although the latter types are not properly boilers). The term intermediate-size has been taken to mean equipment larger in capacity than residential units and smaller than that equivalent to 50 megawatts electrical. This, as above, is an arbitrary definition, but serves to divide the equipment into broad classes which would be controlled by different means. The excluded residential class consists of hot air, hot water, and low pressure steam-generating equipment for central heating up to a capacity for a four-family structure, i.e., about 200,000 Btu/hr rating.

The upper bound (50 megawatts electrical) specified in the scope statement, is equivalent, in terms of boiler capacity, to about 500,000 pounds of steam per hour, using a heat rate of 10,396 Btu per kWh, the reported national average figure for 1967 [2-1].

Larger, modern units operate at lower rates, for example, the lowest rate reported in 1967 was 8,660 Btu per kWh [2-2]. The value used to convert the specified bound to boiler capacity is representative of smaller units. The upper bound conforms approximately to the lower bound of a number of studies on pollution from electric utilities. Several of these studies have already been completed and show the relative merits of a variety of control strategies. Thus, using this limit avoids duplication. The remaining so-called intermediate size includes essentially all of the steam-raising capacity of industry, all commercial space heating equipment, and small-size utility boilers.

Emissions for SO_2, NO_x, and particulates were calculated. Particulates from coal and oil or gas, while quite dissimilar in chemical and physical properties, were considered uniform on a mass emission basis. Cognizance of differences in applicable control methods was made in selecting appropriate strategies.

The base year selected for current estimates was 1967, which was the most recent period for which adequate data on fuel, sales, etc., were all available. Projections were to be made for 1975, 1980, 1985, and 1990. The study was limited to the 48 contiguous states, omitting Alaska and Hawaii.

Following the development of the base year and projected inventory and emission estimates, the significance of the intermediate class as a whole or of any subclass relative to other sources of pollutants was to be determined. The next phase was to identify control strategies applicable to the significant intermediate sources, looking at both currently available technology and at potentially feasible processes. The type of strategies to be examined were as follows:

1. Fuel Switching
2. Flue Gas Treatment
    a. Particulate Collectors Only
    b. SO_2 Removal Processes
    c. NO_x Removal Processes
    d. Combined Treatment Processes
3. Combustion Modification
    a. Combustion Additives
    b. Combustion Design
        Low Excess Air (LEA)
        Flue Gas Recirculation (FGR)
        Two-Stage Combustion (TSC)
    c. Burner Design

Measures of cost/effectiveness were to be developed as a means to compare various strategies and select the most beneficial and promising approaches. Considerations of the combined effects of the three pollutants, the effects of source location, stack height, load practices, and seasonal fluctuations were to be introduced in assessing these benefits.

The last phase was to be the generation of a research and development plan to develop the necessary technology and methodology to implement the most promising strategies.

REFERENCES TO SECTION II

2-1. *Statistical Yearbook of the Electric Utility Industry for 1967*, Edison Electric Institute, New York, 1968.

2-2. "Steam-Electric Plant Construction Cost and Annual Production Expenses - 20th Annual Supplement," Report S-192, Federal Power Commission, November 1968.

III. INVENTORY OF BOILER CAPACITY, FUEL USE, AND EMISSIONS

A. METHODOLOGY

In examining the results following, it is important to note the methodology and assumptions on which the results are based. The approach used in this study differs significantly from most other air pollution studies in that it does not calculate emissions directly from fuel consumption data. Instead, an inventory of boilers in terms of installed capacity was established and emissions were calculated by applying operating and emission characteristics to the boiler ratings. It is believed that while fuel-use figures are useful in establishing emissions, they do not provide a good data base for control strategies.

The inventory was built up on the bases of sales and production figures and on distributive factors (regional, user, etc.) based on samples derived from field surveys and published data. The accuracy of the final results depend on the realism of these various samples. It was not possible to check the validity of each sample against independent data, as such data were not generally available. Instead, the overall validity was established by comparing fuel use calculated according to the formulas used herein with fuel use from independent sources, which data are available and are reasonably precise. That comparison indicated, as will be shown below, that the results obtained herein were in excellent agreement with other fuel data, and inferentially that the approach was valid, and that the estimates were representative of the population of intermediate boilers now operating.

The methodology employed in developing the estimates is detailed in Appendix A.

During the development of the source inventory and pollutant emission estimates, it was necessary to include all stationary combustion equipment in the base inventory and then exclude the lower and upper classes defined above to arrive at the intermediate-size figures by difference. Thus, the results presented and discussed below contain some data pertinent to the total installed capacity of boilers in addition to the main results on the intermediate-size classes. The evaluation of control strategies was restricted to only the intermediate-size range.

The development of the inventory and emission estimates rests on a substantial data base, gathered from a large number of sources, including equipment manufacturers and trade associations, government publications, NAPCA studies, trade journals, state and local boiler inspection agencies and air pollution control departments. A substantial portion of the fine structure of the results, e.g., fuel, user, and firing type distribution, was derived from statistical analyses of information contained in a series of annual surveys of boilers in Power magazine running back to the early 40's. Data on over 7,000 boilers were extracted from this source and were employed to determine usage patterns for watertube boilers.

Lacking such a convenient data source on firetube and cast iron boilers, a series of field trips to boiler licensing agencies were made during which data, similar to that available in the Power survey for watertube boilers, were extracted from various records. The data collected thereby were similarly processed.

The processing of quantities of basic data to extract the information needed for the preparation of a detailed inventory, and subsequently the preparation of the inventory itself, was feasible only through application of a variety of computer programs. Extensive utilization of time-sharing services facilitated the development of the programs. Standard statistical routines were used for preparing summaries and regression analyses. Special programs for manipulating the inventory data base were developed. A comprehensive general emission inventory and cost-effectiveness program (STRAT) was prepared and has been used to generate most of the data reported herein.

B. DEFINITIONS

It is important, before examining the results, to define the various categories used to identify and classify fossil-fuel burning equipment, and to note the codes that sometimes appear in computer printouts in place of names (see Table 3-1). Fossil-fuel burning equipment is broken down according to:

1. Size and type combinations
2. Region
3. User
4. Fuel
5. Firing type (for coal only)
6. Age

1. Size/Type

Seven (7) size/type classes have been employed. These are watertube boilers in four sizes, and a single class for each of the three smaller types of equipment, firetube boilers, cast iron boilers, and all residential central heating equipment, respectively. The four watertube size groups correspond more or less to sizes used by industry and government agencies to classify sales data. The smallest group comprises boilers under 100,000 pph. These boilers range from some very old, quite small (5,000 pph) boilers to modern industrial package boilers. The next size is 100,000 to 250,000 pph. The upper limit corresponds roughly to the large-size package boilers now being produced. This class of equipment is principally used in industrial applications, although small utility plants continue to utilize boilers of this size.

The two larger size groups, 250,001 to 500,000 pph and over 500,000 pph are generally lumped together with available industry data sources. Boilers of these sizes are field-erected. The split into two classes has been made in conformance with the definition of intermediate size. The very large (over 500,000 pph) boilers are almost exclusively used in electric utility plants. The upper limit in this class is pushing 10,000,000 pph. A small percent of the boilers in this class are used in industrial applications, mostly in the larger petroleum and petrochemical complexes in the South.

TABLE 3-1

BOILER CLASSES AND CODES

Size/Type	
Watertube under 100,000 pph	WT 1
Watertube 100,001-250,000 pph	WT 2
Watertube 250,001-500,000 pph	WT 3
Watertube over 500,000	WT 4
Firetube	FT
Residential	RES
Cast Iron	CI
Region	
Atlantic Coast Megalopolis	AT
Industrial Great Lakes	GL
Far West and South	WS
Central Urban	CU
South East	SE
Rural North	RN
User	
Residential	RES
Commercial	COM
Industrial	IND
Utility	UTL
Fuel	
Gas	GS
Residual Oil	RO
Distillate Oil	DO
Coal	CL
Firing Type (Coal)	
Pulverized Coal	PV
Cyclone	CY
Overfed Stoker	OF
Spreader Stoker	SS
Underfed Stoker	UF
Age	
Under 10 years old	1
10-20 years old	2
20-30 years	3
over 30 years	4

Firetube boilers range up to about 650 boiler horsepower or about 22,000 pph. Only one size grouping has been utilized. These boilers are widely used in both commercial and industrial operations. Apartment house, hospital and school space heating is often provided by a battery of firetube boilers where, historically, a single large watertube unit might have been used. The most widely used modern firetube boiler design is the scotch type [3-1].

The residential class includes all equipment for central heating of single family and multiple family dwellings (up to 4 or 5 family size). This class includes hot-air furnaces, and hot water and low-pressure steam units.

The cast iron boiler class identified in this study includes only units larger than residential size. Cast iron type boilers are an important segment of the residential boiler class. The small units have been included in the residential category and are not analyzed in detail in this study. Those remaining run from about 200,000 Btu/hr units up to large commercial boilers of about 5,000 pph capacity. Recent discussions with manufacturers of this type of boiler indicate that cast iron units are now being produced in sizes up to nearly 400 hp (16,000 pph).

Large air heaters both for central heating and space heating were not included in the inventory. These units, in the larger than residential size classes, are not presently significant in capacity relative to any of the other types. The use of large direct-fired air heaters is, however, rapidly growing and may become a significant factor in the future. Almost all types are gas-fired so that the only potential pollution problem will be emissions of nitrogen oxides.

2. Regions

It was determined early in this study that subdivision of the United States into some set of regions would be necessary to reflect the differences in fuel use practices, age, demographic and economic character, and climate which exist within the country. Six regions were chosen on the basis of uniformity of climate, age, urban character, according to a study carried out by Urban Analysis Corporation under subcontract [3-2].

The six regions are shown in Figure 3-1. The results of the inventory and emissions estimate are highly regionally sensitive as will be shown below. The particular choice of regions appears to be very satisfactory in this regard. The characteristics of six regions are summarized below. Note that the regions are not necessarily composed of contiguous states. An examination of the DHEW regions was made to determine their acceptability as a basis for the geographic distribution to be used in this study. The characteristics of those regions are quite non-uniform and do not serve the purposes of this study.

Summary Description of Regions

Atlantic Coastal Megalopolis - A very dense, nearly continuous band of large, mature, urban areas. The urbanization is supported by an exceptionally broad economic base including a wide variety of types and sizes of manufacturing enterprises as well as the nation's educational, financial, and government centers. The region experiences moderately cold winters and uses oil for most of its space heating. The pollution problem is aggravated by shallow atmospheric mixing depths but relieved by relatively high wind speeds and the infrequency of low-level stability.

Industrial Great Lakes - A second group of large, mature, urban areas, different only in degree from the Atlantic coastal megalopolis, having slightly less dense surroundings, somewhat wider spacing of urban centers, and an economy more characterized by large, mass-production industry. The two regions also differ in fuel use, with the Great Lakes region dividing its consumption among coal, oil, and gas. Although the region is characterized by relatively favorable atmospheric dilution, the population and industrial load results in high pollution levels.

Far West and South - A group of large, new, fast-growing, urban areas which are widely scattered over otherwise sparsely-settled

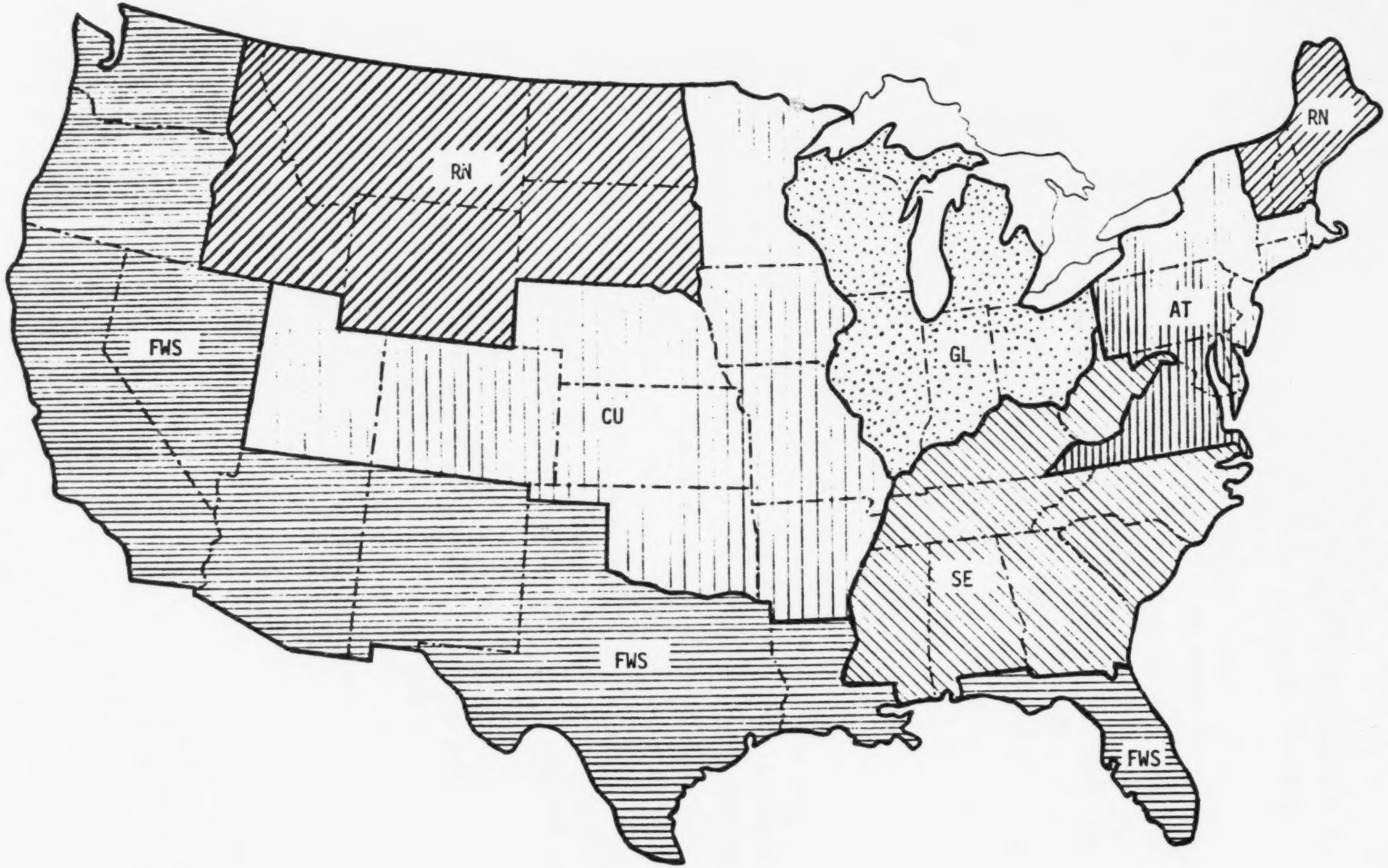

RN
RN
FWS
CU
GL
AT
SE
FWS
FWS

Figure 3-1. Regional Boundaries

territory. Relatively little manufacturing and warm climate tend to mitigate pollution from stationary combustion units. The large, disperse urban areas, however, generate high volumes of automobile exhaust, which in several areas are concentrated by poor atmospheric conditions.

Central Urban - Medium-size, widely-separated, relatively new, metropolitan areas supported by manufacturing and the surrounding rural and town populations. Because of the relative concentrations of population in urban areas, these states rank surprisingly high in the Census definition of "urban" population. Gas is the principal fuel for space heating in this cold-winter region. Atmospheric conditions are relatively good except in Colorado and Utah.

South East - A region with cities whose size and distribution are similar to those in the central urban region. But the cities are more mature, are surrounded by denser statewide population, and have slightly more manufacturing. The warmer climate reduces the emissions from space heating but frequent atmospheric stagnation concentrates the pollutants which are emitted.

Rural North - An area of low density, with only a few small metropolitan areas and with little manufacturing. Although it includes some of the nation's coldest territory, pollution is relatively low because of the low density. The New England states included in this region have somewhat higher densities and some manufacturing.

3. User

There are four user groups employed in the study: residential, commercial, industrial, and (electric) utility. Residential use is defined as that in all dwellings up to five family units. Commercial use includes apartments and dwellings of larger size, schools, hospitals, retail trade, and all other non-manufacturing enterprises. Industry includes all manufacturing companies (SIC codes 19-39) [3-3]. Utilities are all the public and private electric utility companies.

Subdivision into user groups was carried out to provide means for introducing differences in load factor, emission levels, equipment age, etc., which factors depend on user (as well as others).

4. Fuel

Fossil fuels were grouped by the common major classes -- gas, residual oil, distillate oil, and coal. It was essential to distribute equipment accurately according to fuel burned in order to obtain meaningful results. The methods with which proper allocation by fuel were made are described in Appendix A.

5. Firing Type (coal only)

Coal-burning equipment was subdivided according to the type of firing equipment. The many different styles of feeding mechanisms were classed by five overall types. Pulverized coal burning accounts for most of the larger size equipment, with a small fraction of the cyclone type. Smaller equipment generally is fired by one of the three general stoker classes -- overfire, underfire, and spreader [3-1]. Hand firing of coal has all but disappeared and was neglected in the distribution.

Coal-burning units were distributed by the type of firing to reflect differences in emissions and differences in control costs. Emission factors for the various general types of stokers are different [3-4]. No such distribution of oil-burning units by firing type (pressure atomizing, rotary cup, etc.) or arrangement (horizontal, tangential) was made. There was insufficient data on differences in emissions and costs, and on the real distribution in operating units to support a similar distribution for oil-burning units. Differences in emissions from horizontal and tangential firing arrangements have been noted [3-5].

6. Age

Age of equipment is important in assigning proper load factors and particulate collector efficiencies and in determining the retirements in projecting ahead. Four age classes were utilized:

1. Equipment less than 10 years old
2. Equipment 11 to 20 years old
3. Equipment 21 to 30 years old
4. Equipment over 30 years old

C. RESULTS

The results of the 1967 inventory are discussed below. Table 3-2 gives a complete summary of the 1967 results.

Figure 3-2 shows the distribution of total boilers by users. Residential capacity is the largest class of equipment followed in order by utility, industry, and commercial. Fuel use is a significant factor in determining emissions and, as will be shown below, residential fuel use practices drop the importance of these boilers to the bottom rank as far as air pollution is concerned. Annualized load factor, expressed as percent of the time the equipment runs at full load, ranges from about 50 to 60% for utilities to about 15 to 25% for residential use, which causes a smaller share of the total air pollution to be a result of residential fossil-fuel combustion.

The installed capacity of intermediate-size boilers in 1967 consists of mostly commercial and industrial units and some small utility boilers, shown on a regional basis in Figure 3-3. The Atlantic, Great Lakes, and Far West and South regions represent approximately 75% of the U.S. capacity of intermediate boilers. The preponderance of equipment in these regions correlates strongly with the population, age, and industrial characteristics of those regions relative to the country as a whole.

A little over half of this 1967 capacity consists of watertube boilers and the other half is more or less equally distributed over firetube and cast iron units.

Examining present ambient levels in a number of metropolitan areas, the absolute emissions from intermediate-sized sources appear to be significant in terms of air quality standards, independent of their relative share of the total emission level. In this regard, it is

TABLE 3-2

1967 SUMMARY OF RESULTS

	Capacity (10^6 pph)	CL (10^6 tons)	RO (10^6 bbls)	DO (10^6 bbls)	GS (10^{12} cu ft)	SO_2 (10^6 tons)	NO_x (10^6 tons)	Particulates Controlled (10^6 tons)	Particulates Uncontrolled (10^6 tons)
Watertube ≤500,000 pph	1,838	132	194	14	1.72	6.93	1.54	3.83	na
Firetube	813	11	98	69	1.12	.88	.24	.29	na
Cast Iron	757	11	56	37	1.03	.73	.15	.27	na
INTERMEDIATE BOILERS*	3,370	154	348	120	3.87	8.54	1.93	4.39	7.99
Residential	2,117	---	---	355	3.15	.24	.23	.09	na
Commercial	1,341	26	106	58	1.33	1.52	.36	.77	na
Industrial	1,515	84	192	60	1.99	4.27	1.04	2.39	na
Utilities	1,800	271	156	2	2.76	15.17	3.40	2.03	na
ALL BOILERS	6,773	381	454	475	9.23	21.20	5.03	5.28	25.71
INTERMEDIATE BOILERS BY REGION									
Atlantic	913	40	202	74	.26	2.47	.56	1.23	2.08
Great Lakes	818	62	42	26	.76	3.40	.60	1.75	3.29
Far West and South	770	2	60	5	1.73	.40	.24	.06	.11
Central Urban	399	17	11	3	.72	.94	.21	.54	1.02
South East	362	26	17	5	.32	1.05	.24	.62	1.11
Rural North	108	7	16	7	.08	.28	.08	.19	.38

---

*Totals do not necessarily add up due to rounding.

na = not available from runs presently completed with STRAT.

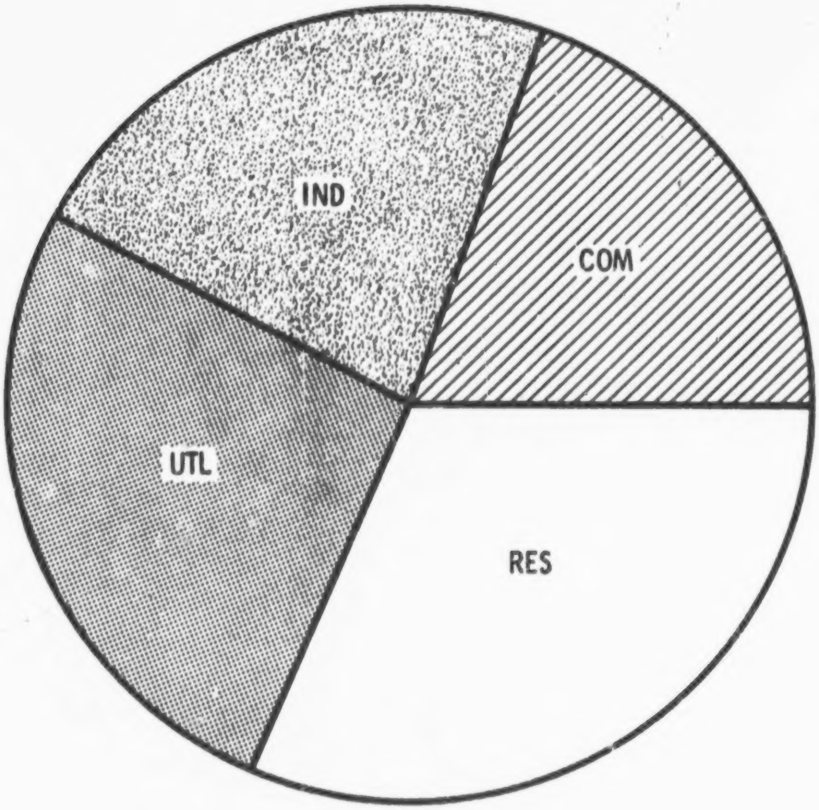


Figure 3-2. 1967 Total Boiler Capacity By User.

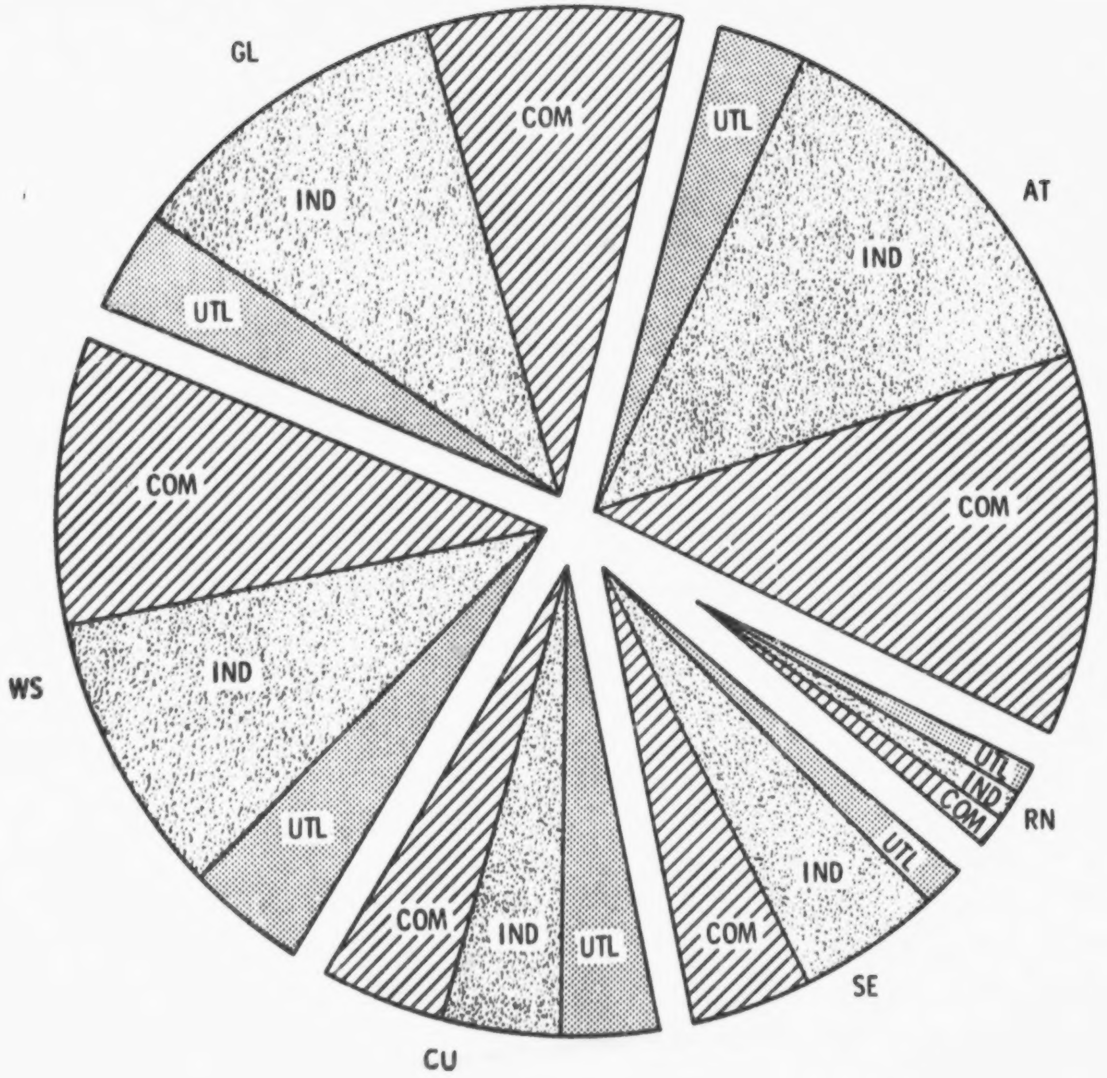


Figure 3-3. 1967 Intermediate Boiler Capacity - Regional By User.

important to note the location of the intermediate sources within metropolitan urban regions. Intermediate sources, particularly commercial space heating boilers, tend to be concentrated in the centers of populated areas and discharge their combustion effluent through low stacks. The larger utilities, particularly new plants, and large industrial complexes, tend to be located remotely and utilize tall stacks. These factors intensify the pollution effects of emissions from intermediate-size equipment.

In periods of intensive space heating, these centrally located sources may be major pollution sources in cities and towns. For example, during the winter of 1966-67, over 55% of the SO_2 emissions from all sources in the Boston Metropolitan Air Pollution Control District came from commercial and industrial combustion sources [3-6]. These sources were also the primary polluters in terms of particulates. It is believed that the seasonal behavior and central location will cause the intermediate boilers to dominate pollution emissions in most cities and towns of the Atlantic and Great Lakes regions, in which 70% or more of the national annual air pollution emissions from intermediate-sized sources are produced (see Figure 3-4). Insufficient local emission inventory data were available to test the general validity of this hypothesis. The Massachusetts data are believed, however, to be representative of most major urban areas in the two regions named.

The emission data for 1967 are shown by user in Figure 3-5 and 3-6 for the total and intermediate-size boilers, respectively. For the total capacity, Figure 3-5, the predominance of utility-generated emissions for SO_2 and NO_x agrees with the emissions estimates based on fuel data [3-7,3-8]. The major contribution to particulate emissions by industry also agrees with other estimates [3-8,3-9]. On an uncontrolled basis, utility particulate emissions far outweigh the others.

Looking at emissions from intermediate sources, Figure 3-6, the exclusion of large-size utilities and residential boilers amplify the relative importance of industrial and commercial users. Higher load factors

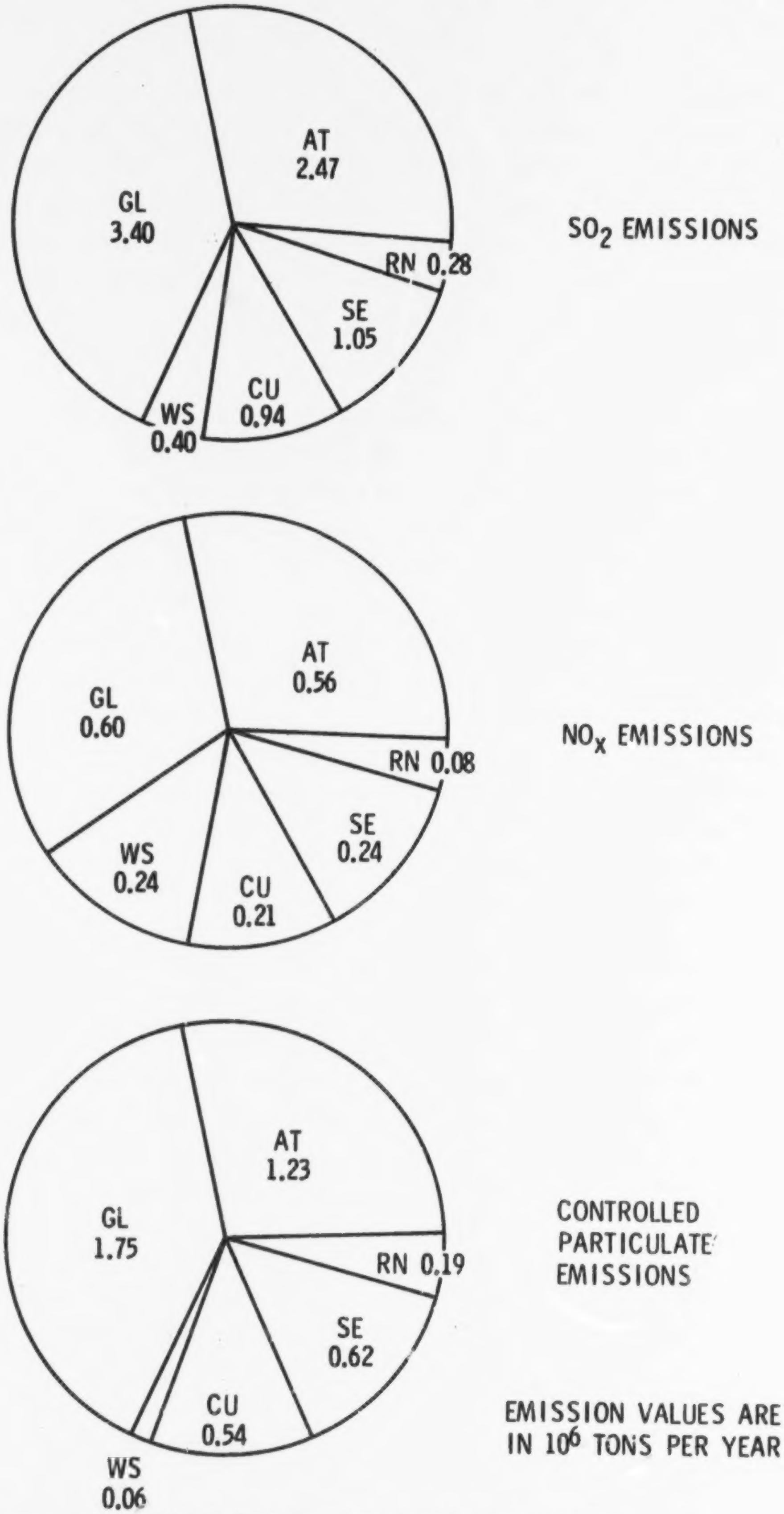


Figure 3-4. 1967 Emissions - Regional Distribution.

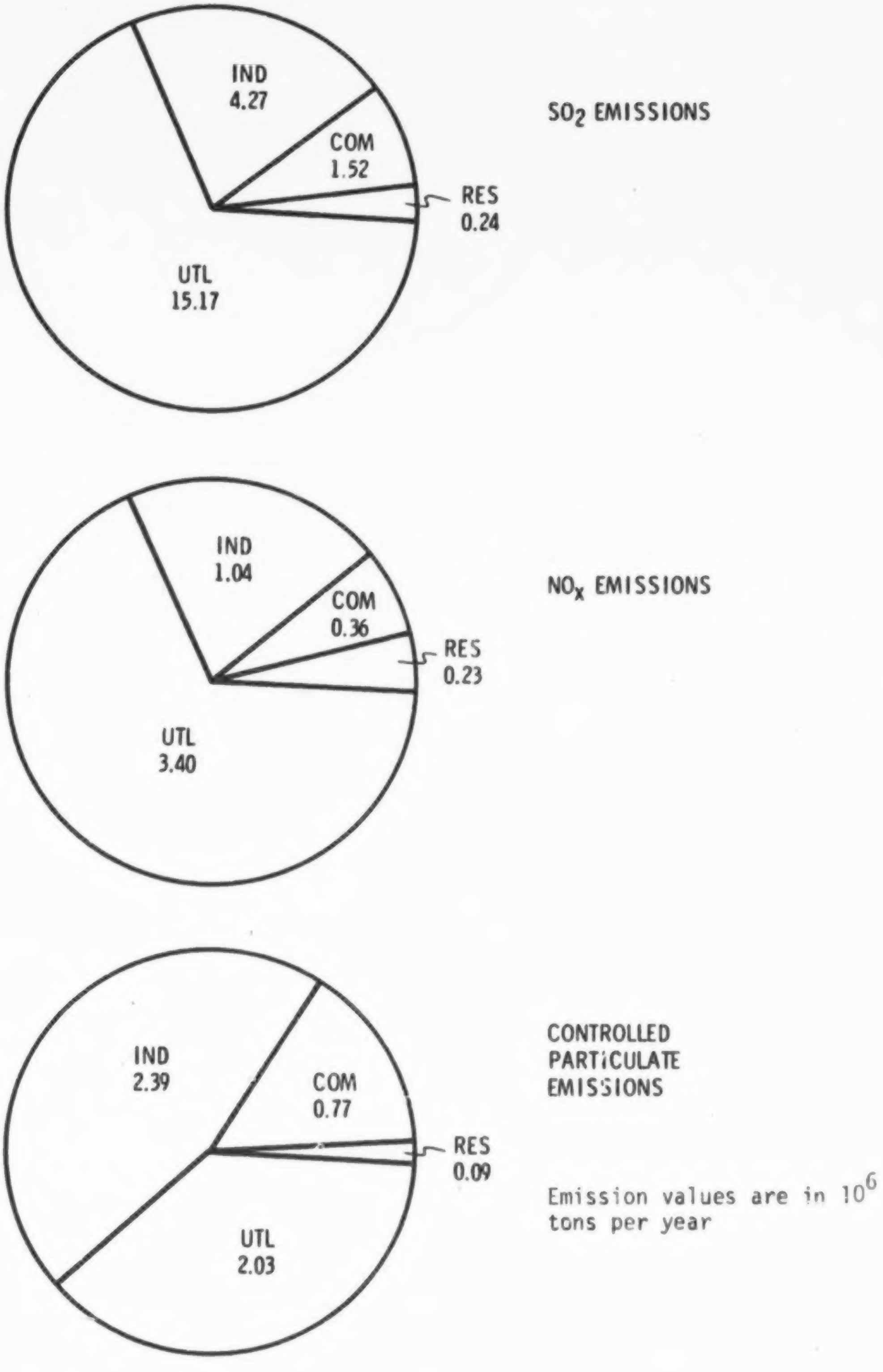
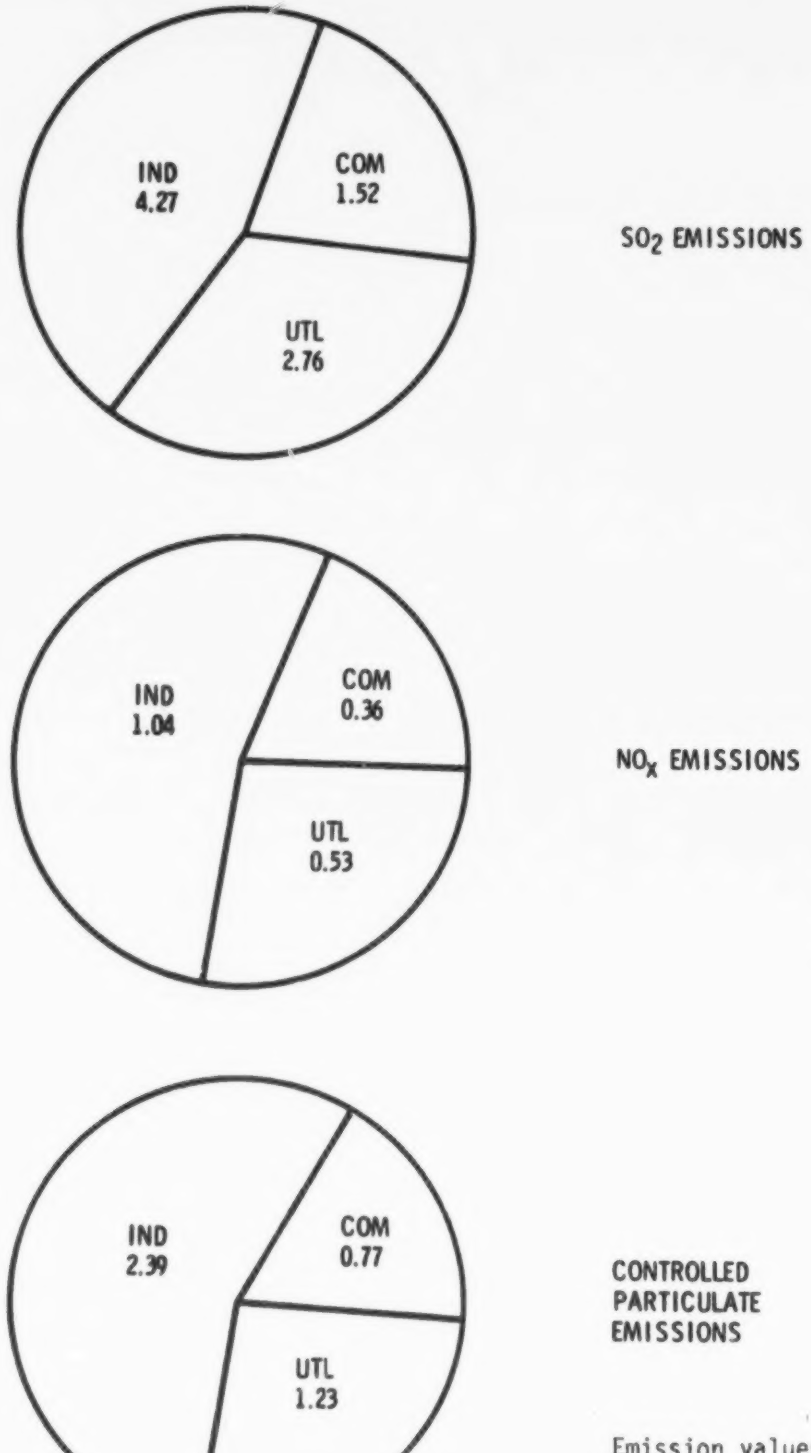


Figure 3-5. 1967 Emissions from All Boilers By User.



Emission values are in 10^6 tons per year

Figure 3-6. 1967 Emissions from Intermediate Boilers by User.

for utility and industrial users, as above, magnify their contributions relative to commercial. The smaller utility boilers and industrial boilers are used about the same amount of time, 35 to 45%. Lower load factors were used for small utility boilers than for the larger types to account for real load practices, where the larger units are used for base loading, and the smaller, less efficient units for peaking. Commercial load factors are based on space heating requirements and are identical to the regional factors used for residential boilers as detailed in Appendix A.

Figure 3-4 above contains a chart of the same emission data on a regional basis. The predominance of pollution problems in the Atlantic and Great Lakes region is immediately evident. Whereas considerable shift occurs in the user patterns when changing from the total to the intermediate bases, regional patterns for both groupings do not change significantly.

The several figures above show the relative contributions according to the individual pollutants. In evaluating strategies, it is significant to examine the effectiveness of a given control approach on all three pollutants combined. Implicit in evaluating the combined effect is the application of some weighting factor, as simply adding up the annual emissions in tons cannot be representative. A simple combining scheme adding the percent contribution of SO_2, NO_x, and particulates (referred to 300% as the whole) has been adopted. On this basis, Figures 3-7 through 3-10 show the relative contribution of various subelements of the intermediate-size group to total pollution from that group.

Coal-burning watertube boilers are by far the most significant contributors (about 75%) to the total intermediate burden (Figure 3-7). Non-coal-burning watertube units, firetube units, and cast iron units more or less share the remaining portion. The next three figures show further breakdown by equipment size (3-8), user (3-9), and region (3-10). The smaller size class (WT-1) is the major source. Industrial users are the dominant class, with utilities close behind. Commercial use of coal in watertube boilers is relatively small. The number of coal watertube units is about 10,000, only about one-fourth of the intermediate watertube boilers. As shown in Figure 3-11, illustrating the distribution of

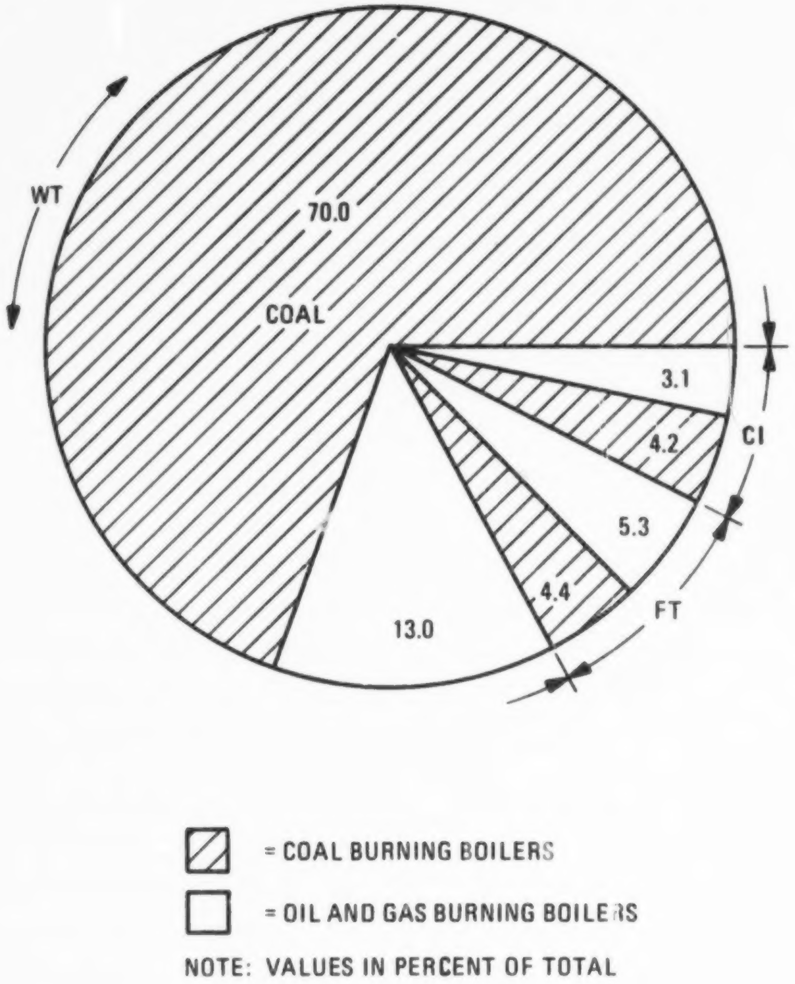


Figure 3-7. Combined Emissions (1967) from Intermediate Boilers - By Type and Fuel.

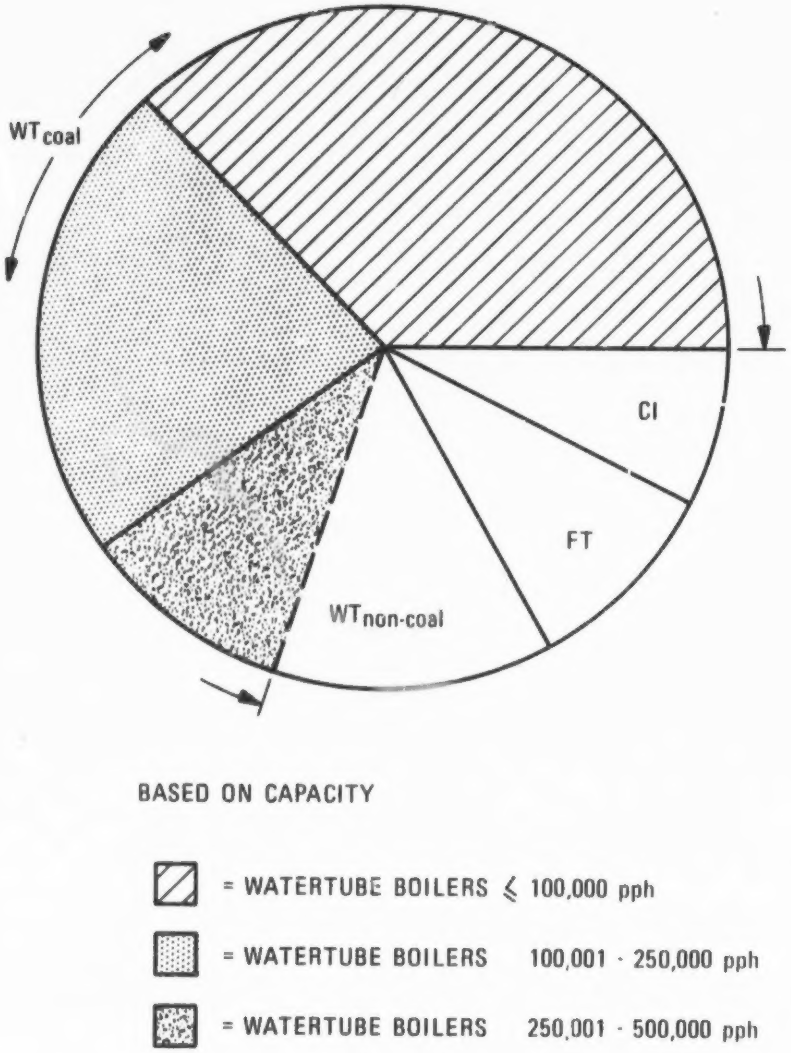


Figure 3-8. Combined Emissions (1967) from Intermediate Boilers - By Size.

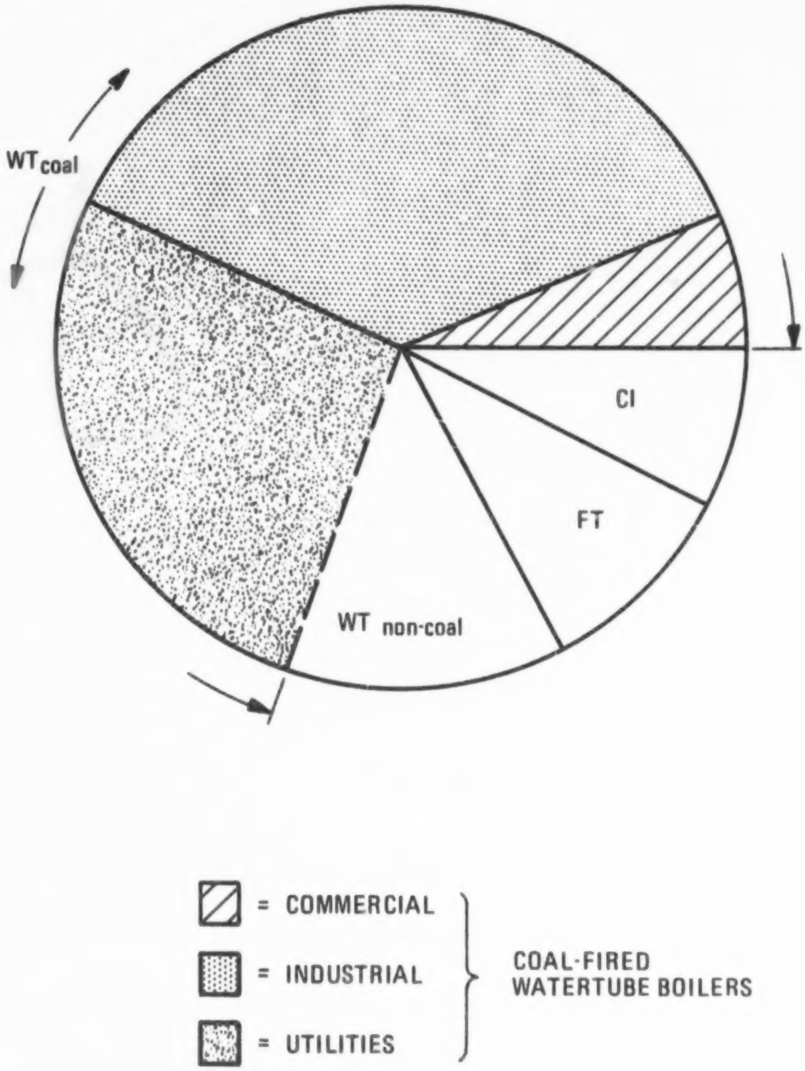
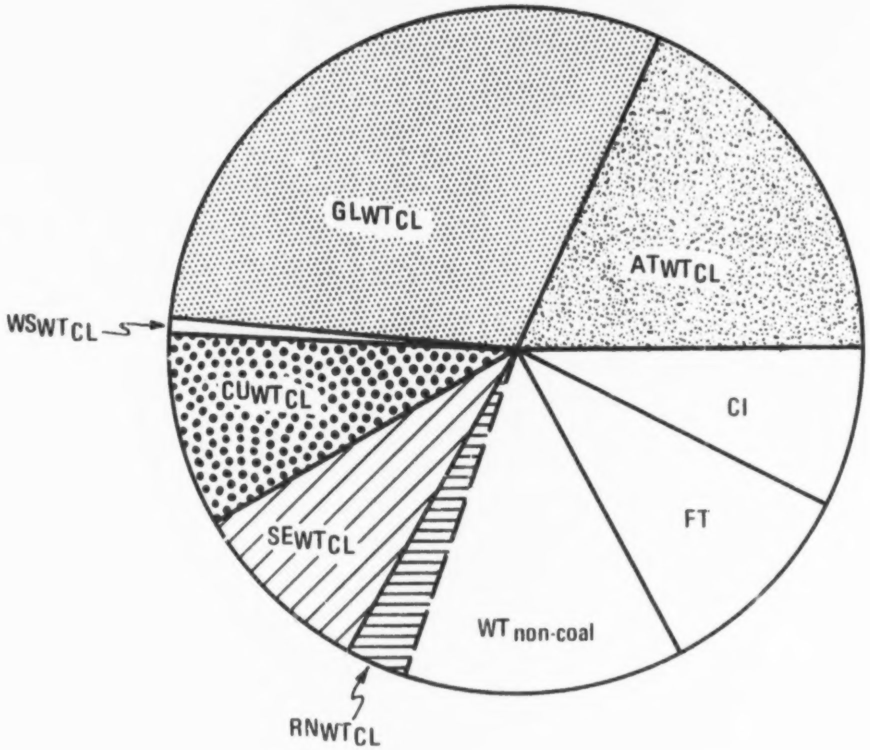


Figure 3-9. Combined Emissions (1967) from Intermediate Boilers - By User.



NOTE: The emissions from coal-fired watertube boilers have been subdivided by region in this diagram as $AT_{WT_{CL}}$ indicates the percentage of the combined pollutants derived from coal-burning watertube boilers in the Atlantic Region.

Figure 3-10. Combined Emissions (1967) from Intermediate Boilers - Coal-Fired by Region.

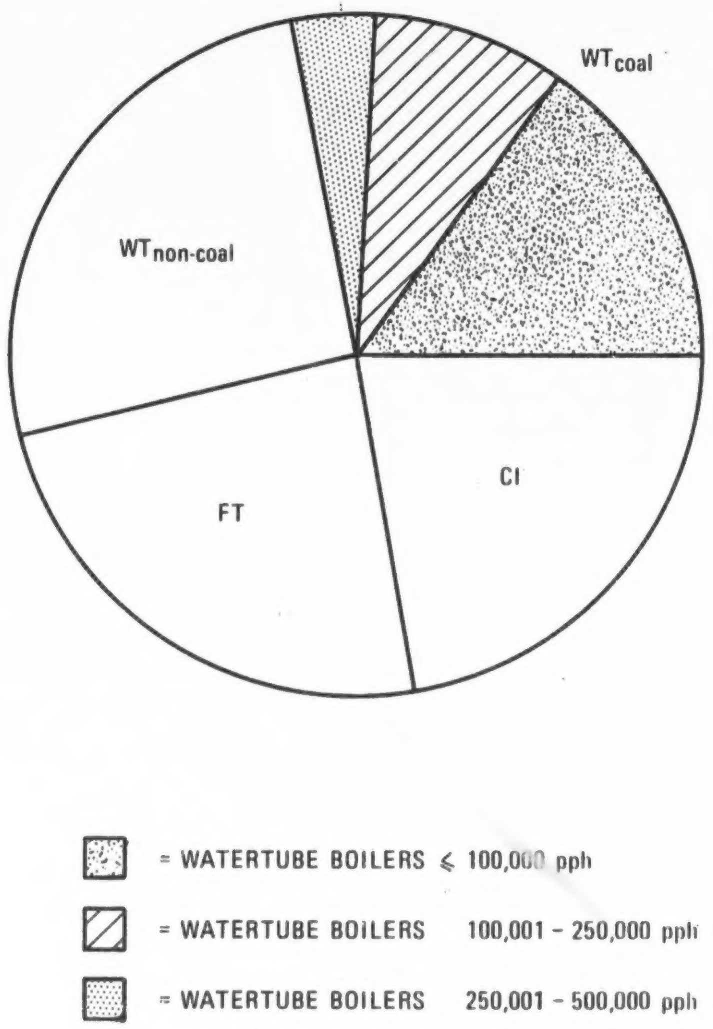


Figure 3-11. Capacity of Intermediate Boilers - By Type.

capacity by type, a relatively small fraction of capacity accounts for the major contribution to emissions.

The last of these charts shows that coal-burning watertubes in the Great Lakes and Atlantic regions contribute nearly half the total burden. These characteristics have been carried into the selection of strategies, e.g., switching from coal to gas or oil only in these two regions.

It will be shown below that the fuel consumption based on the boiler inventory closely matches fuel consumption derived from independent sources, on total, regional, user, and fuel-by-fuel bases. Also, the emission estimates (when directly comparable) fit well into the range of data from other sources.

Validation of the whole process by which the 1967 inventory and projections have been derived has shown the general usefulness of this approach used in this study. The data base now available can be configured to obtain estimates of emissions and control costs for any combination of subsets of the whole conventional boiler inventory. Updating is quite simple and straightforward.

The emission estimates generated in this study are, unlike most comparable works, based on capacity (not fuel) data coupled with several distributive and operational factors. It was essential to examine these results, vis-a-vis other data, to determine the overall accuracy.

In order to compare the results of the 1967 emissions calculated by Walden with those of others, the following summary tables of emissions were prepared (Tables 3-3 to 3-8). Where comparison is possible, such as for utilities, the Walden figures are in reasonable agreement. Where direct comparisons were not possible, the tables merely show a ranking of emissions.

Sulfur oxides emissions estimates depend on the percent sulfur assumed to be present in the fuel burned. The specific values used in

TABLE 3-3

1967 UTILITIES SO_2 EMISSIONS

Walden	10^6 tons	10^6 tons	Other Sources
Utilities Fuel Combustion	15.15	14.0 [3-11] 13.1 [3-12] 13.0 [3-13,3-14]	Utilities Fuel Combustion 1966
Utilities Coal Combustion	13.90	11.9 [3-12] 10.8 [3-15]	Power Plant Coal Combustion 1966

TABLE 3-4

1967 RANKING OF SO_2 EMISSIONS

	10^6 tons
All Sources 1966	28.64 [3-12]
All Sources 1966	28.5 [3-13]
All Stationary Sources 1966	22.2 [3-12]
All Stationary Fuel Combustion 1966	21.20 *
All Watertube Boilers 1967	18.36 *
All Boilers Fired by Coal 1967	18.17 *
Industrial Fuel Combustion 1968	9.3 [3-15]
Intermediate Boilers 1967	8.53 *
Non-Utility Boilers 1967	6.05 *
Industrial & Commercial Boilers 1967	5.81 *
Industrial Fuel Combustion 1966	5.5 [3-11]
Industrial Boilers 1967	4.28 *
Residual Oil in Stationary Sources 1966	3.3 [3-8]
Residual Oil in Boilers	2.76 *
Residential & Commercial Boilers	1.77 *

---

*Developed by Walden

TABLE 3-5

1967 UTILITIES NO_x EMISSIONS

Walden	10^6 tons	10^6 tons	Other Sources
Utility Boilers 1967	3.42	3.6 [3-7]	Electric Utilities 1968
		3.5 [3-11]	Power Plant Fuel Combustion 1966

TABLE 3-6

1967 RANKING OF NO_x EMISSIONS

	10^6 tons	
All Stationary Sources 1968	9.6	[3-7]
All Stationary Sources 1966	7.2	[3-16]
All Fuel Combustion in Stationary Sources 1966	6.7	[3-10]
All Boilers 1967	5.03	*
Watertube Boilers 1967	4.4	*
Industrial Fuel 1965	4.4	[3-17]
Industrial Fuel 1966	3.1	[3-4]
Industrial Combustion 1968	2.8	[3-7]
Intermediate Boilers 1967	1.9	*
Industrial Boilers 1967	1.03	*
Fuel Oil in Stationary Sources 1966	.9	[3-8]
Fuel Oil in Boilers	.82	*

---

*Developed by Walden

TABLE 3-7

1967 UTILITIES PARTICULATE EMISSIONS

Walden	10^6 tons	10^6 tons	Other Sources
Controlled Utility Boilers 1967	2.03	2.3 [3-11]	Controlled Power Plants 1966
		2.3 [3-9]	Controlled Power Plants 1968
Uncontrolled Utility Boilers 1967	20.6	18.9 [3-15]	Uncontrolled Power Plants 1968
		18.5 [3-9]	Uncontrolled Power Plants 1968
		16.3 [3-18]	Uncontrolled Power Plants 1969

TABLE 3-8

1967 RANKING OF CONTROLLED PARTICULATE EMISSIONS

	10^6 tons	
All Stationary Sources 1966	6.0	[3-8]
All Boilers 1967	5.28	*
Boiler Coal Combustion 1967	4.97	*
Intermediate Size Boilers 1967	4.4	*
Industrial Fuel 1966	3.0	[3-11]
Industrial Boilers 1967	2.39	*
Residential & Commercial Boilers 1967	.86	*

---

*Developed by Walden

this study are shown in Appendix A. Sulfur content was introduced into the calculations as a function of user and region. There are only scant data on sulfur content in fuels as consumed. The national average sulfur content assumed for utility coal, the major contributor to emissions, was 2.7%, which corresponds to the value used in a recent study by the National Academy of Engineers [3-10]. An average sulfur in residual oil of 2.5% was used. No change in sulfur content for the future years was introduced.

REFERENCES TO SECTION III

3-1. Shields, C. D., Boilers, McGraw-Hill, Inc., 1969.

3-2. "Preliminary Delineation of Regions," Urban Analysis Corporation, August 5, 1969.

3-3. Standard Industrial Classification Manual, prepared by the Office of Statistical Standards, U.S. Government Printing Office, 1967.

3-4. Duprey, R. L., "Compilation of Air Pollutant Emission Factors," U.S. DHEW, PHS Publication No. 999-AP-42.

3-5. Sensabaugh, J. D. and Jonakin, J., "Effect of Combustion Conditions on Nitrogen Oxide Formation in Boiler Furnaces," ASMA Paper 60-WA-334, 1960.

3-6. Morgenstern, P., Goldish, J. C., and Davis, R. L., "Air Pollutant Emission Inventory for the Metropolitan (Boston) Air Pollution Control District," Report to Massachusetts Department of Public Health, Walden Research Corp., June 1970.

3-7. Bartok, et al., "Systems Study of NO_x Control Methods for Stationary Sources," Esso R&D Co. (NAPCA Contract PH 22-68-55), November 1969.

3-8. "Reference Book Summary of Nationwide Emissions," NAPCA, DHEW, June 1969.

3-9. Devitt, T., "Particulate Systems Study," Midwest Research Institute Quarterly Report No. 2, CPA 22-69-104, September-December 1969.

3-10. "Abatement of Sulfur Oxide Emissions from Stationary Combustion Sources," National Academy of Engineering-National Research Council, Washington, D.C., 1970.

3-11. Mason, et al., "Sources and Air Pollutant Emission Patterns in Major Metropolitan Areas," APCA Paper No. 69-101, 1969.

3-12. "Sulfur Dioxide Pollution Control," Arthur D. Little, August 1969.

3-13. Sherwood, T. K., "Must We Breathe Sulfur Oxides," Technology Review, January 1970.

3-14. Hangebrauck, R. P. and Spaite, P. W., "Controlling the Oxides of Sulfur," JAPCA, 18, No. 1, January 1968.

3-15. Converted from fuel consumption data given in "Cost of Clean Air." First Report of the Secretary of Health, Education and Welfare to the Congress of the United States on the Air Quality Act of 1967. June 1969.

REFERENCES TO SECTION III (continued)

3-16. Crawford, A. R. and Bartok, W., "Survey of NO_x Emissions in U.S. with Projections to the Year 2000," presented at Annual APCA Meeting, June 1969.

3-17. Converted from fuel consumption data in Morrison, W. E. and Readling, C. L., "An Energy Model for the U.S.," U.S. Bureau of Mines, Information Circular 8384, July 1968.

3-18. Converted from fuel consumption data in "Competition and Growth in American Energy Markets 1947-1985," Texas Eastern Transmission Corporation, 1968.

IV. DISCUSSION OF 1967 ESTIMATES AND PROJECTIONS

The results of projections of capacity, fuel use, and annual emissions are presented in this chapter. The projections were made to assist in the selection of control strategies that would fit the source patterns anticipated in the future. In addition, discussions of regional characteristics of the data, and of the current and projected fuel use patterns are presented. A summary of the methodology used to develop the projections is given below in Section A. The approach is presented in full detail in Appendix B.

A. METHODOLOGY AND ASSUMPTIONS

The procedures followed to generate projections of emissions and fuel use were identical with the base year methodology. New capacity inventories for each future year were developed by adding projected sales to the 1967 estimates and subtracting retirements according to Equation 4-1:

$$\text{Capacity}_{t_i} = \text{Capacity}_{1967} + \sum_{t=t_o}^{t=t_i} \text{sales} - \sum_{t=t_o}^{t=t_i} \text{retirements} \qquad (4\text{-}1)$$

where $t_o = 1967$

$t_i = 1975, 1980, 1985, 1990$

Distributive factors (region, user, fuel) were developed from projections of certain socio-economic factors.

The results of the projections in this study depend strongly on the assumptions described below. The projections were based on past trends and mainly reflect the demands for the equipment and fuel involved, with little emphasis placed on supply functions.

a. Projections were based on correlations between boiler sales and economic indicators, such as gross national products derived by applying stepwise regression analysis to historical data.

b. Future values for the economic indicators were obtained by means of linear regression over time. This approach removes all cyclical components from the model, a limitation which is of little significance in this study, which was concerned only with projections over five-year periods and not short-term year-by-year projections.

c. Qualitative judgment was superposed on the projection results where it appears that trends had changed drastically in the past few years, making certain periods of sales of less importance to the future trends.

d. Actual sales data were used, where available, instead of projected figures, i.e., for 1968 and 1969.

e. Retirements based on the estimated life-span of the various boiler types were calculated on a first in-first out basis, using sales figures.

f. Percentage of watertube sales in the greater than 500,000 pph size segment as well as user distribution of the projected boiler inventories were estimated by means of recent trends and socio-economic factors.

g. Regional distribution of the projected boiler inventories were based on socio-economic factors, for which projections were obtained from the Bureau of Census and National Planning Associations.

h. Fuel distribution of the projected boiler inventories were based on region-by-region linear fuel projections, adjusted to reflect the resistance build-up due to saturation, limited supply, and higher costs of other fuels.

i. Assumed emission control values were incorporated to reflect a continued increase in particulate control. SO_2 and NO_x emissions were projected both on an uncontrolled basis and assuming controls on large utility boilers.

j. No analysis was made of the fuel supply problems. Except for ad hoc adjustments to growth rate for gas consumption and rate of decline of coal consumption (where the projections appeared unreasonable), the projections rely on the assumption of unlimited fuel supplies for all major fossil fuels considered here.

k. No provision was made to project the encroachment of nuclear energy on conventional energy. It should be pointed out that this factor would solely affect the sale of large utility boilers which were not included in this study. This factor has a significant effect on fuel supply, however.

l. No changes in operating factors such as boiler efficiency, load factor, fuel sulfur content, were assumed in the projections. The same emission factors used in the 1967 estimates were employed.

B. PROJECTIONS OF BOILER INVENTORY TO 1975, 1980, 1985, 1990

The results of inventory projections are summarized in Tables 4-1 and 4-2, by capacity and number of units, respectively. Data for all boiler classes and the intermediate range sizes are included. The same data are shown graphically in Figure 4-1, which displays the different projected growth patterns for the several major boiler classes.

Total watertube capacity is expected to grow very fast in the future, but most of this growth is due to the projected continued use of large utility boilers which do not fall in the intermediate category. In the intermediate group, firetube boilers have been and are projected to continue displacing the smaller watertube units. Firetube are being used in moderately large size installations by ganging the units, up to six at a time. This practice follows the economies achieved in the initial purchase price and the ease of following load change and maintenance schedules by shutting down (in sequence) one or more of the individual units. Their encroachment on watertubes is most evident in the effect on the smallest watertube class which shows the smallest growth pattern of all boiler types. Thus, by 1990, projections based on these trends show the watertube class representing only 37% of the installed capacity of intermediate boilers and the firetube category having increased their share to over 40%.

TABLE 4-1

PROJECTED CAPACITY OF BOILERS BY TYPE AND USER

(Output Rating in 10^6 pph)

	1967	1975	1980	1985	1990
BY TYPE					
Total Watertube	3,086	4,595	5,686	6,950	8,379
Size 1 - Under 100,000 pph	921	1,045	1,123	1,201	1,275
Size 2 - 100,001-250,000 pph	658	700	745	810	898
Size 3 - 250,001-500,000 pph	259	286	282	276	262
Size 4 - Over 500,000 pph	1,248	2,564	3,537	4,663	5,944
Firetube	813	1,365	1,783	2,255	2,650
Cast Iron	757	985	1,098	1,330	1,461
Residential	2,117	2,877	3,359	3,844	4,344
TOTAL BOILERS	6,773	9,822	11,927	14,379	16,834
*Intermediate Size Boilers	3,370	4,335	5,030	5,838	6,602
BY USER					
Commercial	1,341	1,857	2,192	2,578	2,964
Industrial	1,515	1,989	2,333	2,770	3,188
Utility	1,800	3,099	4,043	5,187	6,338
Residential	2,117	2,877	3,359	3,844	4,344

---

*Totals do not necessarily add up due to rounding.

TABLE 4-2

PROJECTED NUMBER OF BOILERS BY TYPE
(in thousand units)

	1967	1975	1980	1985	1990
BY TYPE					
Total Watertube	40.4	35.4	34.7	34.4	34.3
Size 1 - Under 100,000 pph	34.4	28.2	26.7	25.5	24.5
Size 2 - 100,001-250,000 pph	4.01	4.27	4.54	4.94	5.48
Size 3 - 250,001-500,000 pph	0.94	1.04	1.03	1.00	.953
Size 4 - Over 500,000 pph	1.05	1.90	2.40	2.87	3.40
Firetube	239	291	326	362	391
Cast Iron	1,270	1,530	1,710	2,010	2,280
Residential	29,700	36,300	40,700	45,600	50,500

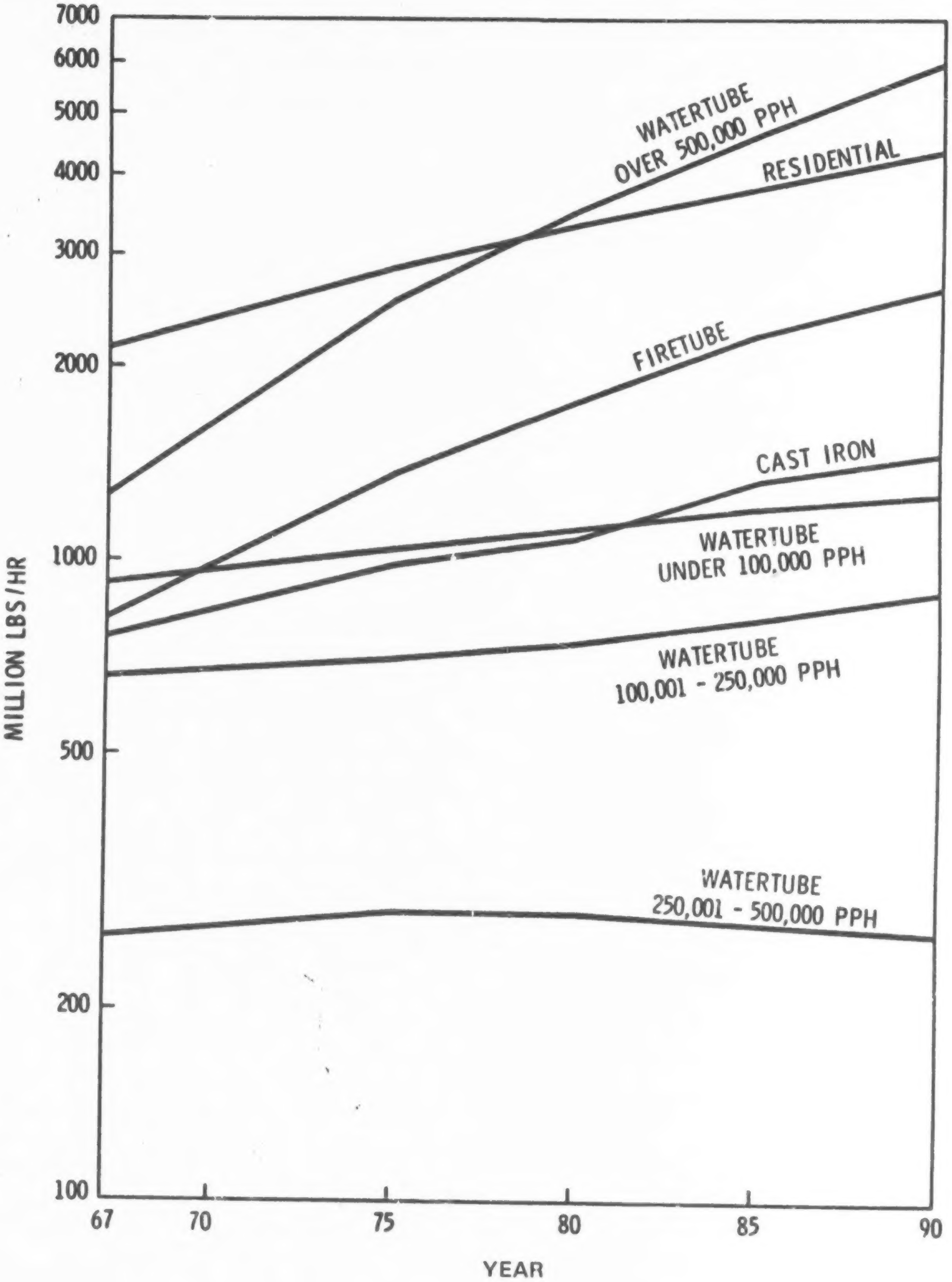


Figure 4-1. Projected Boiler Capacity by Type.

The overall growth of the capacity in the intermediate-size group is substantial. By 1990, it is expected that the capacity for this group will be almost equal to the total boiler capacity installed in the U.S. in 1967. The summary data in Table 4-1 are shown as a bar graph in Figure 4-2 to emphasize this significant finding of the study.

Different use patterns by the four major user groups have a marked effect on the pollutant emissions, as will be shown below. Figure 4-3 displays the growth patterns of total and intermediate boilers by user group.

Residential use follows expected growth of the economically active population and maintenance of present fuel burning patterns. Changes in housing practices, particularly in a move toward multiple-family structures, would result in lower capacity in this category. Based on plans now under consideration, there is some evidence that this might be the trend for urban renewal, low-income housing, moderate-income housing in the suburbs, new cities, and large downtown office-dwelling combination structures. The effects of such a trend would be an increase in firetube capacity or in utility-size boiler, if central steam heating becomes more popular.

Commercial and industrial use of boilers shows a more or less linear increase through 1990. Utility boilers grow at a much faster, almost exponential, rate. Utility production has increased exponentially over the past twenty years (and even further back) doubling every 8.5 years, according to FPC data [4-1,4-2]. The growth shown in Figure 4-3 approximates that growth characteristic except that projected capacity in 1990 is slightly less than that exponential value. This growth pattern largely ignores substitution of nuclear units for fossil-fuel units and in that sense over-estimates conventional steam-electric plant capacity and associated emissions. Since intermediate-size equipment has been emphasized, and since consequences of the no-nuclear-generation assumption are evident primarily in the largest size group, no attempt to adjust capacity for nuclear plant construction was made. The emission data contained below for the total capacity must be interpreted with that understanding.

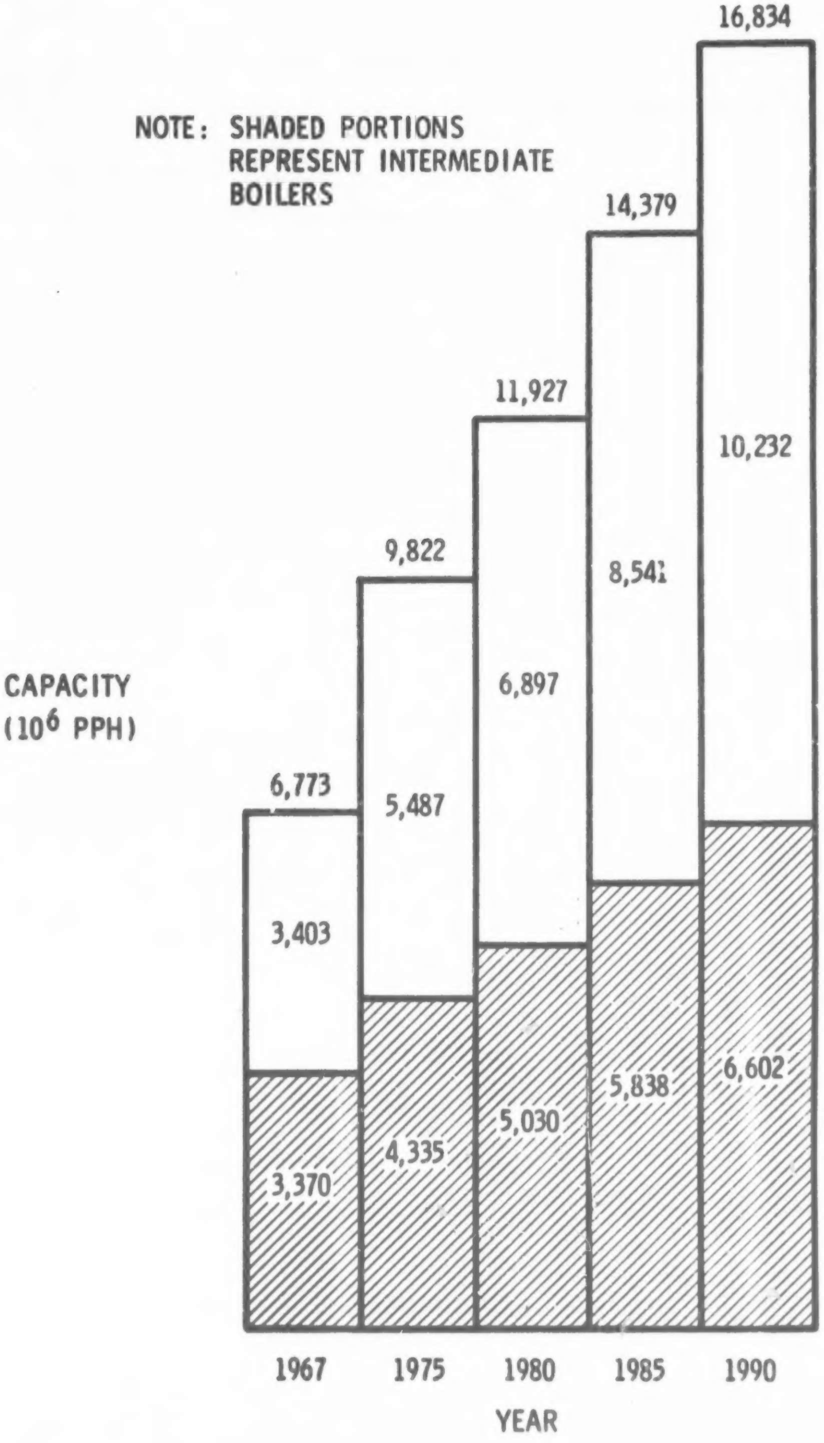


Figure 4-2. Projected Total and Intermediate Boiler Capacity.

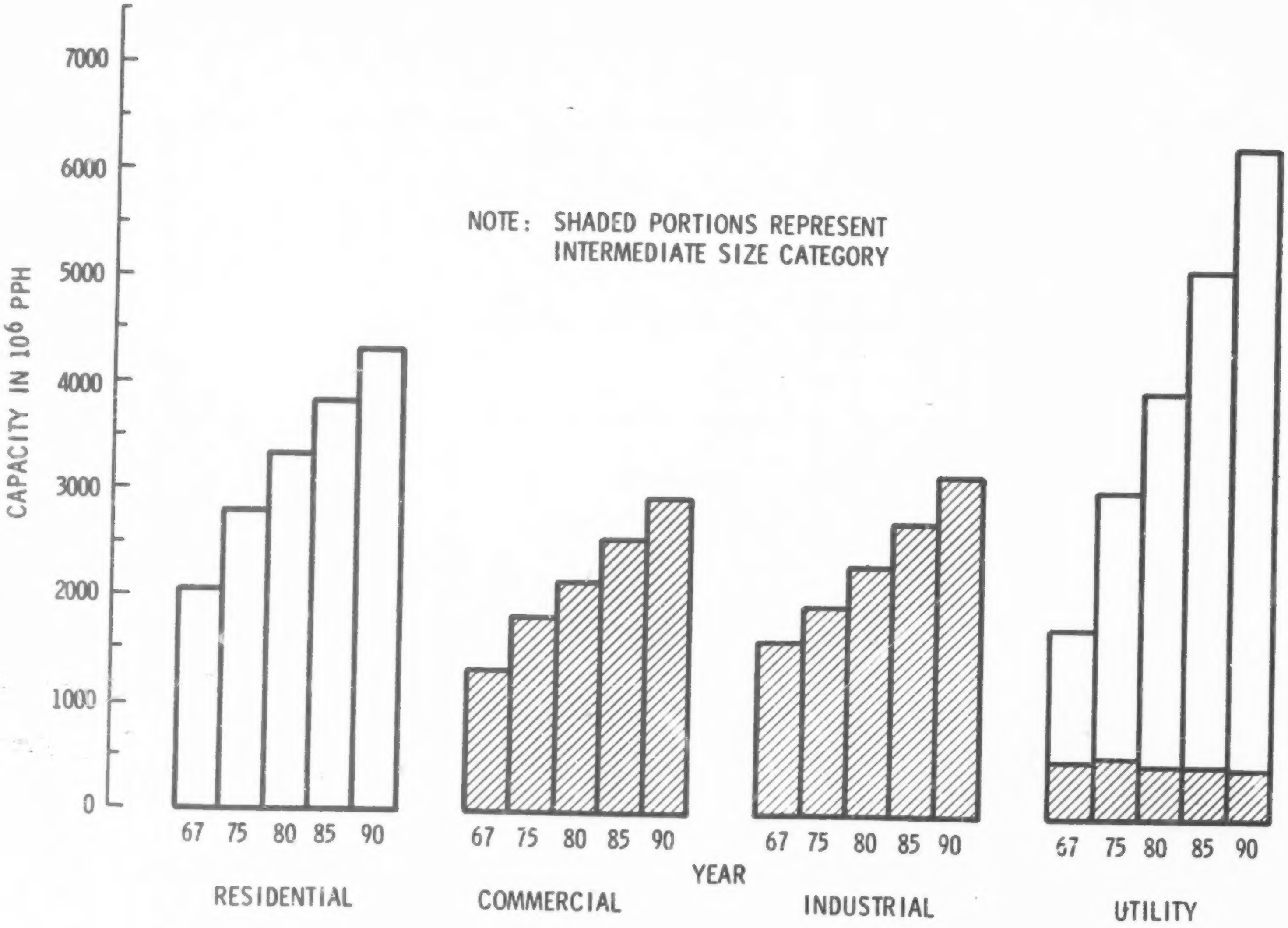


Figure 4-3. Projected Boiler Capacity By User.

The average size of installed and operated boilers is assumed, generally, to increase with time as shown in Table 4-3. The projected values are based on historical trends. The average size of boilers sold in such time periods will be larger than the values shown, which result reflects the integration of new and old units.

C. PROJECTED EMISSIONS

1. Results

Projected emissions from intermediate-size boilers and from all boilers are shown in Figures 4-4 through 4-7. The first two graphs containing the particulate emissions results indicate that particulates from intermediate sources will, if present trends in emissions control persist, continue to be a significant source group. Examining the uncontrolled emissions data (Figure 4-5) shows that this conclusion is very sensitive to the degree of control assumed for large boilers, which exhibit uncontrolled emission levels far outweighing those from intermediate boilers.

Examination of the bar graphs (Figures 4-6 and 4-7 below) showing the growth pattern of uncontrolled SO_2 and NO_x emissions indicates that intermediate-size sources are small relative to the total boiler output and tend to diminish with time. This behavior appears to be due to the almost exponential utility capacity growth compared to the more or less linear industrial/commercial growth projected (Figure 4-3 above) and to the changing fuel use pattern assumed.

It is expected that SO_2 emissions from large boilers, especially utility boilers, will be controlled significantly in the future either by imposition of sulfur in fuel restrictions or through application of flue gas treatment procedures, resulting in a larger share of the emissions coming from intermediate sources. The effect of various assumptions as to the level of control on SO_2 achieved for large (greater than 50 MW) utility or industrial boilers is summarized in Figure 4-8 to show the potential importance of the intermediate-size group with regard to the total air pollution picture from stationary sources.

TABLE 4-3

PROJECTED AVERAGE SIZE OF BOILERS
(pph steam)

Size	1967	1975	1980	1985	1990
Watertube-1	26800	37000	42000	47000	52000
Watertube-2	163900	163900	163900	163900	163900
Watertube-3	274900	274900	274900	274900	274900
Watertube-4	1185000	1350000	1475000	1625000	1750000
Firetube	3400	4620	5470	6160	6840
Residential	103	106	118	121	123
Cast Iron	595	625	644	657	657

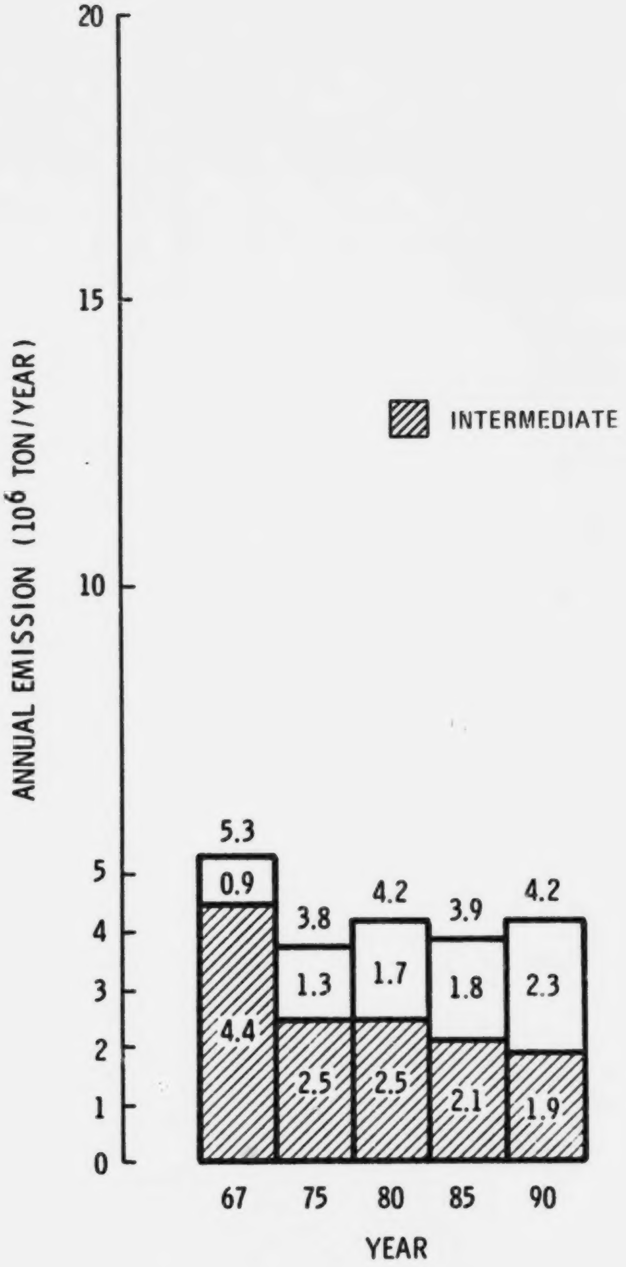


Figure 4-4. Projected Particulate Annual Emission (controlled).

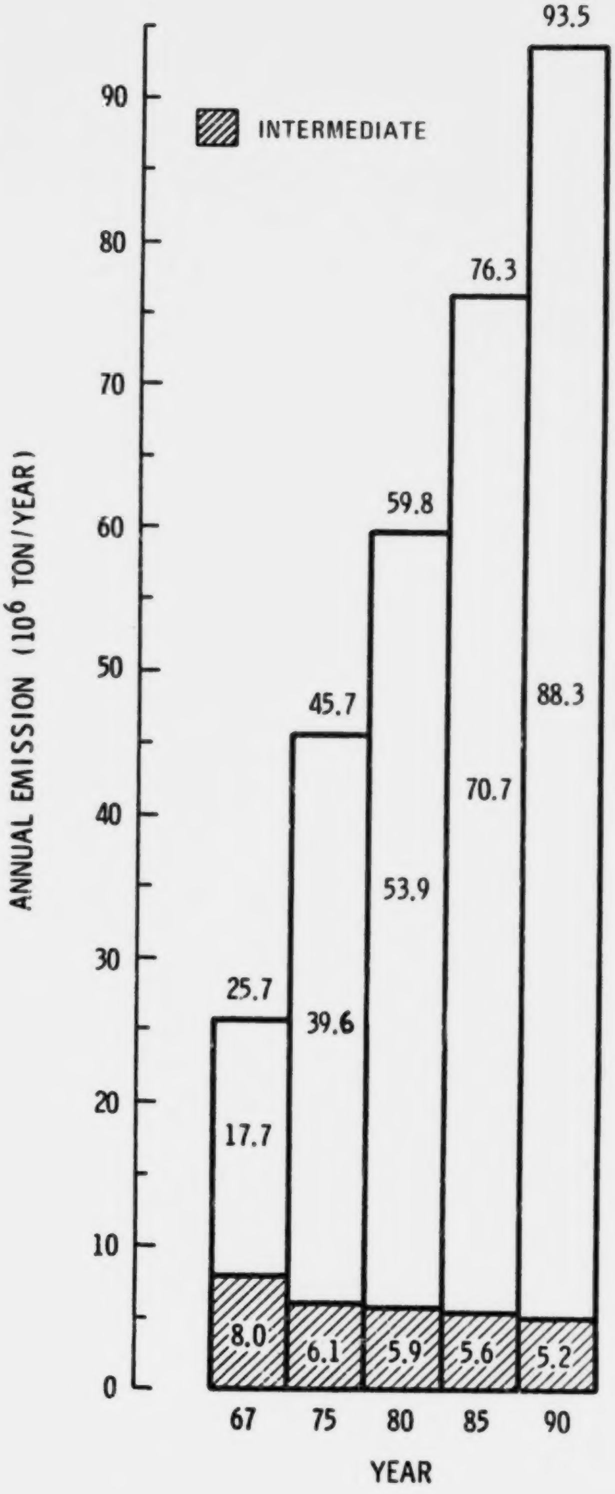


Figure 4-5. Projected Particulate Annual Emission (uncontrolled).

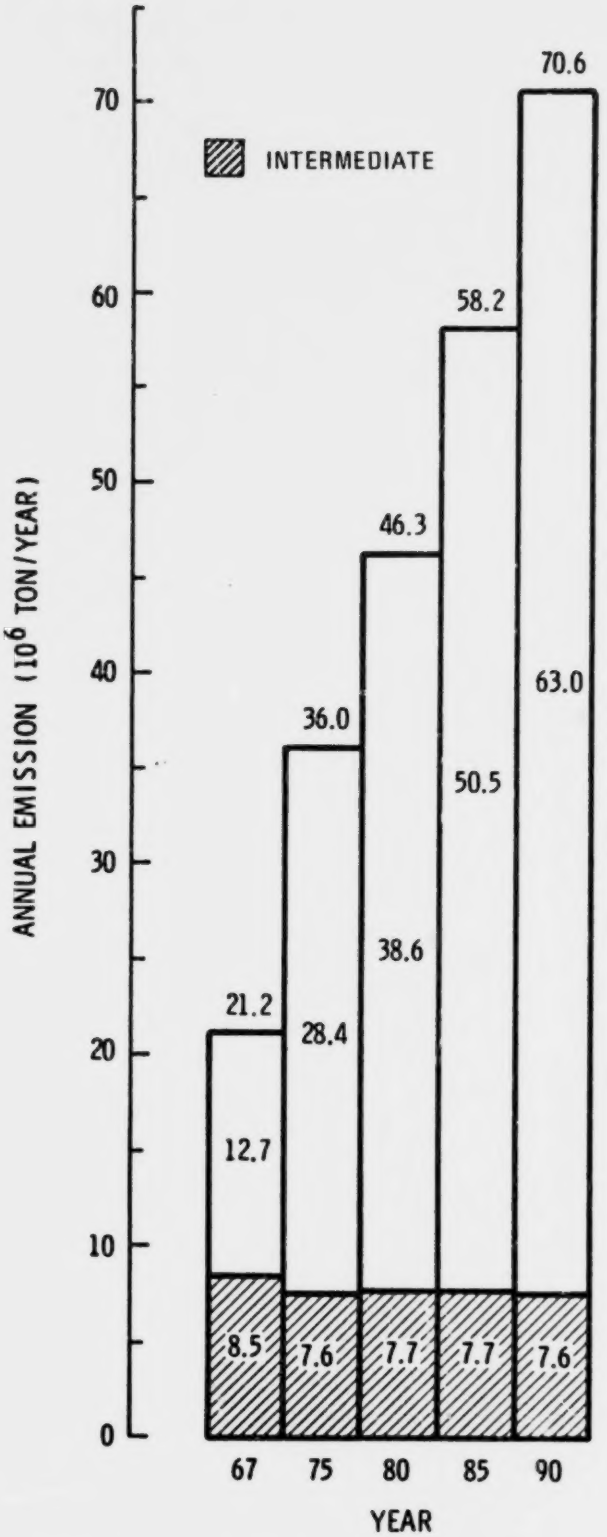


Figure 4-6. Projected SO_2 Emission.

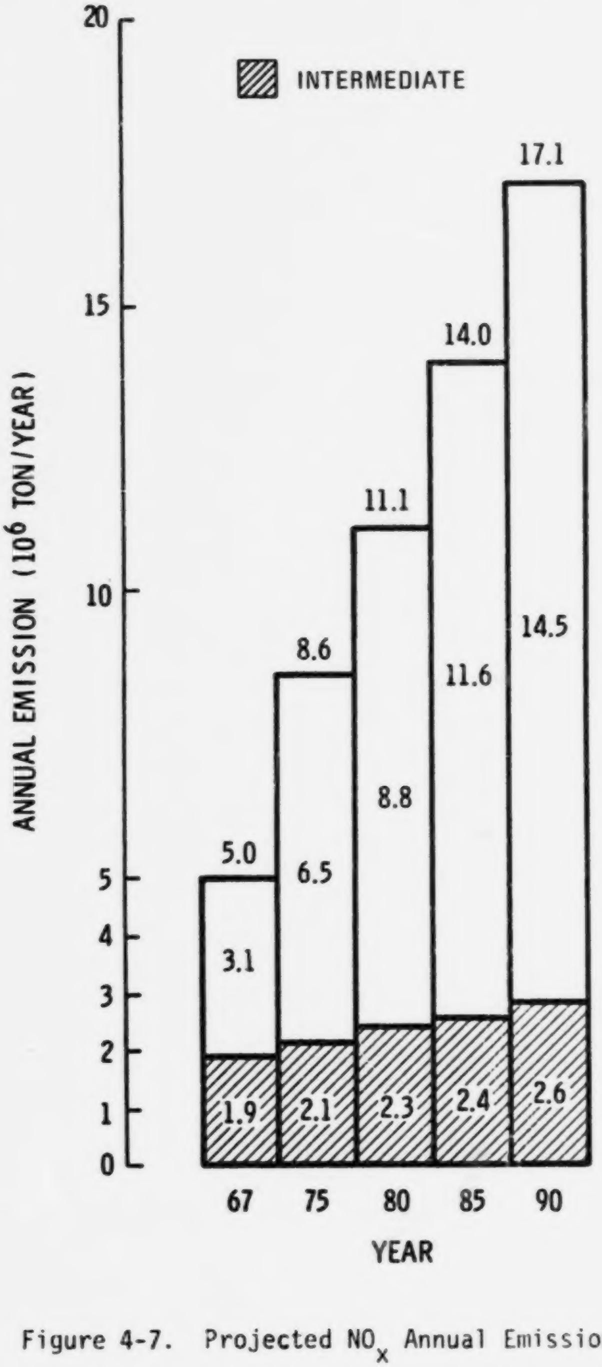


Figure 4-7. Projected NO_x Annual Emission.

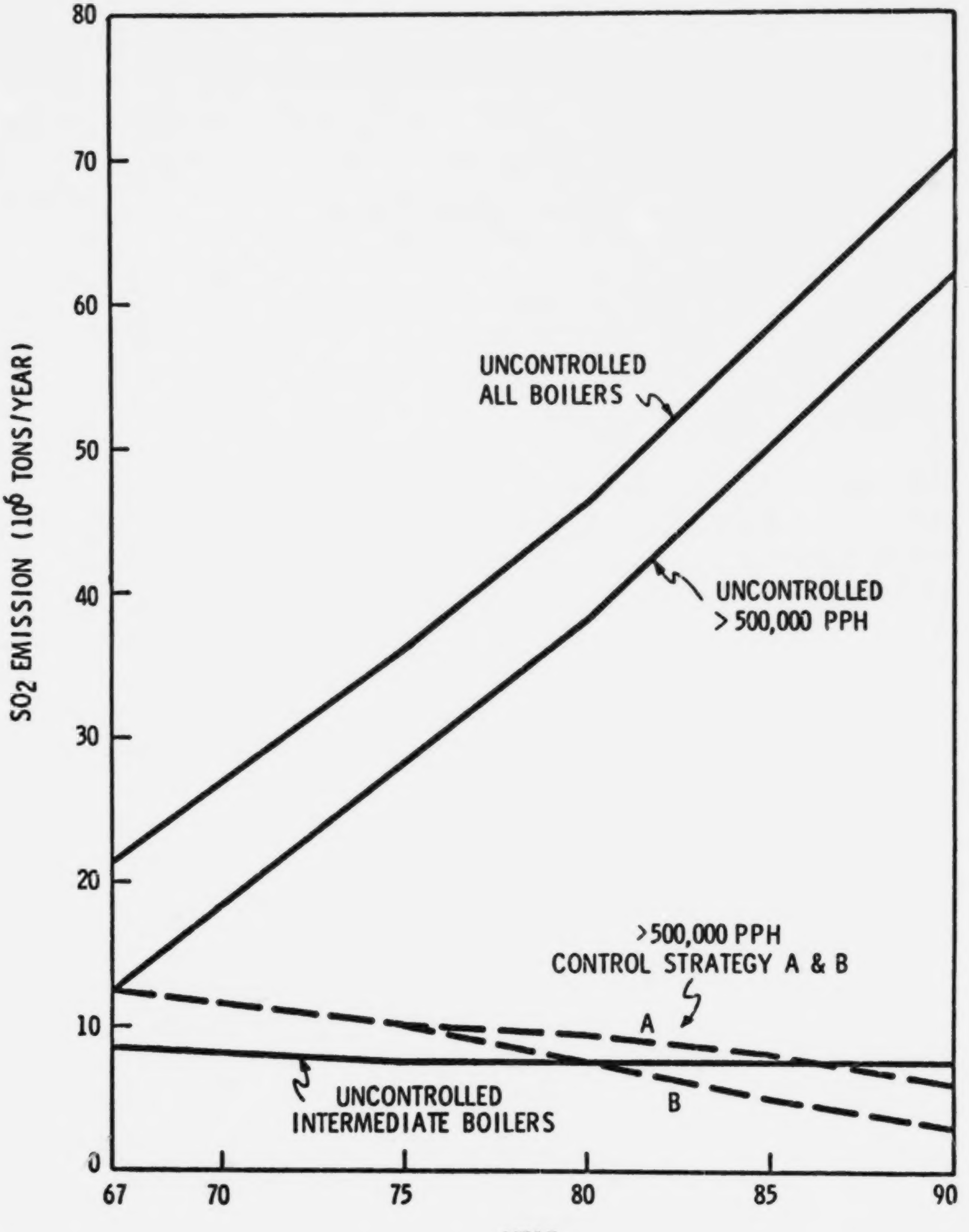


Figure 4-8. Effect of Projected Control Levels on SO_2 Emissions.

SO_2 emissions from intermediate boilers were compared with total SO_2 emissions assuming the percentages of control in the large sources shown in Table 4-4.

TABLE 4-4

ASSUMED SO_2 CONTROL LEVELS
FOR LARGE BOILERS

	1967	1975	1980	1985	1990
Case A	0%	63.6%	75%	83%	90%
Case B	0%	63.6%	80%	90%	95%

For both cases A and B, the percentage control assumed by 1975 was as reported in The Cost of Clean Air [4-3], a report of the Secretary of HEW to Congress. For case A, a slower adoption of SO_2 control was assumed, arriving at 90% in 1990, which would reflect present projected efficiencies. Assuming improved efficiency for SO_2 control, case B shows a faster control scheme, arriving at 95% in 1990. Thus, anticipating control of large-scale stationary sources, it is seen that, as early as 1980 and not later than 1986, SO_2 emissions from intermediate sources may become of greater concern than the SO_2 emissions from the large utility boilers. The trend on an uncontrolled basis, is indicative only of the relative capacity of the several sources, but not of their emissions.

Similar estimates were made for future NO_x control possibilities (Figure 4-9). Although intermediate sources are not expected to emit more NO_x in the future than controlled large sources would, their share in NO_x emissions remains substantial. The percentages of control assumed were 30, 40, 45, and 50 percent for respectively 1975, 1980, 1985, and 1990. These percentages were based on data from the NO_x system study prepared by Esso [4-4].

Whereas controls have not been employed historically for SO_2 and NO_x, particulate emissions have been controlled by a variety of means for many years. These controls have been used more widely on large

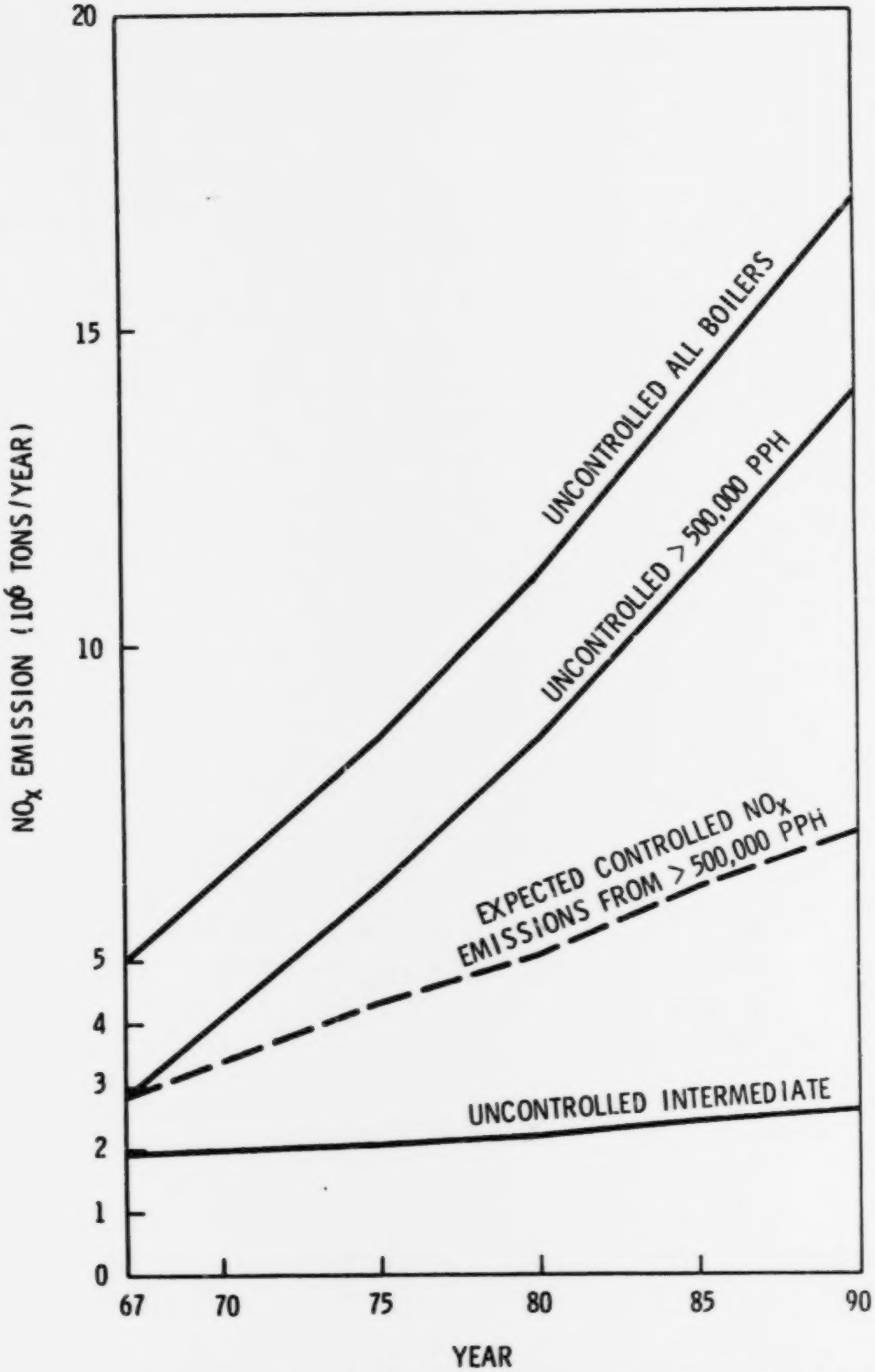


Figure 4-9. Effect of Projected Control Levels on NO$_x$ Emissions.

installations, so that the present relative emissions from intermediate-size boilers are estimated to be a significant part, about 83%, of the total emission. Assuming a continuing trend of levels of particulate control equipment on large boilers, intermediate particulate emissions remain a significant part, about half, of the total particulate emissions. The degree to which emission controls are applied in the computations is discussed in Appendix A, where specific data for assumed values of particulate collector efficiency are presented.

Considering that controls for large stationary combustion sources, both presently available and under development, are pushing the state-of-the-art in efficiency, it appears necessary to look at the intermediate-size range to obtain abatement of SO_2 and particulates beyond that expected from applications of large-scale control technology. For example, little further decrease in particulate emissions can be expected by requiring better controls on utility plants in the future were controls already exceed 99% efficiency. Reduction in levels will require control of intermediate sources. If utility SO_2 emissions can be controlled at the 90% efficiency level, then the intermediate sources will grow to over half of the total by 1990, which portion will exert an even larger effect on ground-level concentration due to source location and seasonal factors discussed above. Further abatement of SO_2 and particulate will almost certainly require some action involving the intermediate sources. Although the projected share of the emissions from intermediate sources, assuming controls on large installations, does not appear to be as sizable as the comparable case for SO_2, the NO_x contributed by intermediate sources will remain a substantial part of the total NO_x emissions resulting from all boilers.

The absolute levels of uncontrolled emissions from intermediate sources projected in the future years are lower than the amount that would be expected from the projected growth in capacity (Figure 4-2). This is directly related to the assumption used herein that fuel use for that group will continue the present trend away from coal burning to the less polluting fuels. It is significant, however, that the total fuel consumed by the intermediate-size group in 1990 is projected to be almost as much as the fuel consumed by all boilers in 1967. If the fuel trends assumed herein do not materialize because of, for example, an inadequate supply of gas (as is often projected today), the air pollution problem attributable to the intermediate group will probably be considerably greater than shown in the figures, and could be as large as the total problem today.

2. Comparison with Other Projections

For the projected years, each of the pollutants is briefly discussed below in comparison with forecasts made by other sources.

SO_2 - Sherwood [4-5] estimates the emission of SO_2 resulting from power plant operations using coal and oil to be 35 million tons in 1975. The Walden result for SO_2 from utilities fuel combustion for 1975 is almost 28 million tons. On the other hand, rough conversions to emissions from fuel projections given in The Cost of Clean Air [4-3] show 17 million tons of SO_2 emitted from power plant fuel combustion. Similar fuel conversions from BuMines projections [4-6] for 1980 show that SO_2 resulting from total stationary combustion will be between 30.7 and 39.7 million tons. The STRAT figure for SO_2 emissions from all boilers is 46 million tons for that year. In 1980, sulfur oxides resulting from power plants will be between 14.5 and 23.5 million tons according to BuMines. Walden results are 40.4 million tons of SO_2 from power plants for that year. For 1990, Sherwood quotes the NAPCA figure of 60 million tons of SO_2 from power plants [4-5]. The estimate herein is about 61 million tons.

From these comparisons, it appears that the SO_2 projections of this study are initially higher than those of others and conform quite closely for later years.

NO_x - Because of extensive data available from the Systems Study of NO_x Control Methods, it is possible to make a direct comparison between Walden's estimates and those made by Esso for NO_x emissions from power plants [4-4]. This comparison is summarized below (Table 4-5).

TABLE 4-5

NO_x FROM POWER PLANTS

	Walden	Esso and Crawford & Bartok (1969)
1967	3.42	3.6 (1968)
1975	6.7	8.2
1980	9.6	9.0
1985	11.6	10.0
1990	14.4	11.0

Esso's projections appear to show an abrupt increase between 1967 and 1975 which is difficult to explain. The growth of NO_x emissions seems to slow down thereafter according to Crawford and Bartok (1969) [4-7]. Walden's figures follow the general trend and seem quite reasonable, though not fully in agreement with the discontinuous growth projected by Esso.

Particulates - Particulate emissions have not been projected into the future by as many sources as is the case with SO_2 and NO_x, especially when particulates under controlled conditions are considered.

Total uncontrolled particulates projected by Walden are 45.7, 59.8, 76.3, and 93.5 million tons respectively for 1975, 1980, 1985, and 1990. For controlled particulate emissions, based on present control trends, Walden shows 3.8, 4.2, 3.9, and 4.2 million tons respectively for 1975, 1980, 1985, and 1990. Midwest Research Institute shows between 2.7 and 3.6 million tons of particulates for 1980 resulting from power plants [4-8] assuming controls. Walden's equivalent figure for 1980 is 2.0 million tons. For 1990, Midwest Research shows between 2.5 and 4.8 million tons of particulates emitted by power plants, Walden estimates this total to be about 2.4 million tons.

Summarizing, it appears that Walden's projections for controlled particulates are slightly lower than the few figures available from preliminary reports by Midwest Research. The particulate emissions value depends on the assumed degree of control. It is extremely difficult to obtain an accurate measure of current installations. One check on the assumptions used in this study can be made by reference to data on fly ash production and disposal. One reference reports that total ash collected in 1969 was 33,370,000 tons [4-9]. Of that total about two-thirds (22,200,000 tons) is fly ash collected. The difference between total uncontrolled particulate emissions and emissions after collectors (which difference is equivalent to collected fly ash) was calculated in this study to be 20,400,000 tons in 1967. Considering growth that would occur in the two years between the 1969 data and the 1967 basis for the inventory, these figures are in excellent agreement which agreement supports the various assumptions made herein as to the frequency of use and efficiency of particulate collectors.

D. GEOGRAPHIC RESULTS

1. Emissions

There are very distinct regional differences in air pollution from stationary combustion sources as indicated in earlier figures. The most striking result is the large proportion of SO_2 and particulate emissions that are produced in the Great Lakes region, where a large percentage of the nation's industry is located. Industrial employment in that region represents 26 percent of the total U.S. industrial employment. The 1969 population of these five states was 20 percent of the total U.S. population. The SO_2 and particulate emissions from stationary boilers in 1967, however, were estimated at 40 percent of the total U.S. SO_2 emissions from this type of equipment.

It is also interesting to note the large percentage relative to population taken up by the South East in the U.S. air pollution pattern. Relative pollution in this region is significantly reduced (from 19 percent to 12 percent for SO_2) when utility watertube boilers over 500,000 pph are excluded from the results. It appears that these large utility boilers are the main sources of air pollution reflecting the several TVA installations in that region.

When the large boilers are excluded on a nationwide basis, the main source of the SO_2 and NO_x pollution switches from the utilities to industrial users. This is not the case, however, for particulate emissions on a regional basis. Looking at the results region by region, one notes:

Atlantic Region (AT) - Excluding the large boilers further decreases the share of the utility industry in the particulate emissions, but only slightly, since these large boilers are usually well-controlled. Utility particulate emissions in this region come mostly from intermediate boilers. Industrial establishments using coal are the main polluters in this region, followed by industrial users of residual oil.

Great Lakes Region (GL) - Again, here, excluding the large boilers somewhat reduces the share of the utility industry in the particulate emissions. The main problem in this region is due to coal burning. Almost half of the pollution is caused by coal burning in industrial establishments.

Far West and Southern Region (WS) - Considering all stationary fossil fuel sources, utilities in this region contribute the largest share of the three pollutants. There is a large number of boilers greater than 500,000 pph in the Far West and South. Almost one-third of the nation's boilers in this category are located here. It is interesting to note that, in spite of widespread control equipment, the share of the particulate pollution caused by these boilers is very large. The reason for this is that total non-utility particulate pollution in this region is small, since hardly any coal is used.

The SO_2 emissions in the Far West and South, although not large on the national scale, are caused mostly by residual oil burned in industrial plants. NO_x emissions are quite significant in this region. Looking only at the intermediate-size boilers, one notes that one-third of the NO_x results from gas combustion in industry. Residual oil burned in industry is the second most important contributor to the NO_x emissions.

Central Urban Region (CU) - Even when the greater than 500,000 pph watertube boilers are excluded, the utilities remain the main source of emissions in this region. There are few very large boilers here. Coal used in utilities, industrial establishments and commercial establishments, respectively, produces the main emission problem in this region.

Rural North (RN) - There are few very large watertube boilers in this region. Total pollution is low in comparison to other regions, except for particulates, which are higher here than in the Far West and South, since, contrary to the West and South, coal and residual oil are the main fuels in the Rural North.

2. Regional Priorities

To determine where the worst problems in air pollution from intermediate stationary sources occur, several factors were computed and examined as shown in Table 4-6 below.

The most direct way to decide on regional priorities would be to rank the regions according to annual emissions. The results thereof were discussed above. Other indicators to measure the importance of air pollution in each region were developed.

Tons of Pollutant per Capita appears to be a meaningful index, but, as a measure of priority, tends to lend more importance to areas that are less densely populated. In other words, if two regions would have the exact same amount of annual air pollutant emissions, the per capita emissions in the region with the lowest population figure would be highest. Thus, this factor is a poor priority index.

Tons per Unit Area tends to emphasize the non-population-dependent problems of air pollution and might be a useful index in conjunction with others.

TABLE 4-6

PRIORITY INDEXES

(Intermediate-Size Boilers Only)

	million metro-population-tons	million tons	tons/mi^2	tons/thou persons	million population-tons
			SO_2 (1967)		
AT	113 (1)	2.5 (2)	14.6 (1)	45.1 (2)	139 (1)
GL	96 (2)	3.4 (1)	13.7 (2)	86.8 (1)	133 (2)
WS	15 (3)	.4 (5)	.4 (6)	8.2 (5)	19 (5)
SE	11 (4)	1.0 (3)	2.9 (3)	37.0 (4)	27 (3)
CU	11 (5)	.9 (4)	1.3 (4)	40.5 (3)	20 (4)
RN	negl (6)	.3 (6)	.6 (5)	5.6 (6)	2 (6)
			NO_x (1967)		
AT	25 (1)	.56 (2)	3.3 (1)	10.1 (3)	31 (1)
GL	17 (2)	.60 (1)	2.4 (2)	15.3 (1)	24 (2)
WS	9 (3)	.24 (3)	.2 (5)	4.9 (6)	12 (3)
SE	3 (4)	.24 (4)	.7 (3)	8.9 (5)	6 (4)
CU	3 (5)	.21 (5)	.3 (4)	9.4 (4)	5 (5)
RN	negl (6)	.08 (6)	.2 (6)	14.9 (2)	negl (6)
			Particulates (1967)		
AT	56 (1)	1.23 (2)	7.2 (1)	2.2 (5)	68 (2)
GL	49 (2)	1.75 (1)	7.0 (2)	4.5 (1)	69 (1)
SE	7 (3)	.62 (3)	1.8 (3)	2.3 (4)	17 (3)
CU	6 (4)	.54 (4)	.8 (4)	2.4 (3)	12 (4)
WS	2 (5)	.06 (6)	.1 (6)	.1 (6)	3 (5)
RN	negl (6)	.19 (5)	.4 (5)	3.5 (2)	1 (6)

NOTE: Numbers in parentheses show ranking.

Population-Tons or Metropolitan Population-Tons is the product of population and emission figures. This index is the most significant of the above from a health and other human effects point of view. Thus, to use our previous example, if two regions have the exact same emissions, the region with the highest population will receive a higher priority index and should be taken care of first. The metropolitan population-tons figures show a subjective priority in favor of the metropolitan population suffering from the air pollution in each region.

There are many other ways to arrive at such simple indexes. One could consider potential growth, death rates, etc. These factors do not, of course, attempt to be all-inclusive damage functions, but were intended to develop some kind of perspective on the relative importance of the air pollutants by region. The results indicate that no matter what kind of index is used, the Atlantic and Great Lakes regions remain the most significant.

Attention must be paid, however, to the Far West and South and the South East regions as well because of the more rapid rates of growth and economic development in these regions.

3. Regional Trends

A comparison between the 1967 and the 1990 emissions for the various regions is shown below in Table 4-7.

TABLE 4-7

TRENDS IN EMISSIONS FROM INTERMEDIATE BOILERS 1967-1990 (10^6 tons/year)

	SO_2			NO_x			Controlled Particulates		
	1967	1990	+/-	1967	1990	+/-	1967	1990	+/-
AT	2.47	3.29	+	.56	.93	+	1.23	.60	-
GL	3.40	2.51	-	.60	.67	+	1.75	.82	-
WS	.40	.33	-	.24	.43	+	.06	.09	+
CU	.94	.36	-	.21	.20	-	.54	.07	-
SE	1.05	.91	-	.24	.34	+	.62	.31	-
RN	.28	.16	-	.08	.06	-	.19	.02	-

The Central Urban and Rural North regions are expected to experience decreases in emissions of all three pollutants discussed above. This is due to the large projected shift from coal to natural gas for industrial and commercial users in these regions. At this point it must be emphasized again that this shift does not take the supply aspect of natural gas into account.

Fuel use practices and trends in the various regions are significantly different, a fact which is reflected clearly in the table.

The national shift from coal to natural gas is occurring in all regions, but in some regions this process is taking place at a slower rate than in others. Also, in some regions such as the Atlantic, the substitution of coal is being split over natural gas as well as the fuel oils, causing, for example, the substantial increase in SO_2 emissions projected for that region.

E. FUEL USE

1. Discussion

The fuel consumption by the total and intermediate-size boilers is shown in Tables 4-8 and 4-9. The data in Table 4-8 are all expressed in heat content (Btu) to simplify direct comparison among fuels, while those in Table 4-9 are given in conventional quantity units.

An understanding of changing pollution patterns in the future depends on the knowledge of fuel use practices as well as equipment trends. This section is a short discussion of national fuel use projections, a subject of significant importance on its own merits, and widely discussed in the literature. The discussion that follows below is intended only to highlight those few aspects which can help elucidate the results developed herein, and which support the assumptions implicit in developing the regional fuel projections used (see Appendix B).

Many studies have generated projections of the increased total fuel use and/or the increasing generating capacity in the utility

TABLE 4-8

CALCULATED FUEL USE (HEATING VALUE) U.S. TOTALS

	Fuel Consumption in 10^{15} Btu				
	1967	1975	1980	1985	1990
TOTAL BOILERS					
Coal	9.30	14.75	20.42	23.73	28.77
Distillate Oil	2.92	3.71	4.41	4.84	5.92
Residual Oil	2.77	4.55	5.56	6.73	7.69
Gas	9.54	15.20	17.55	23.72	28.14
TOTAL	24.53	38.21	47.94	59.02	70.52
INTERMEDIATE					
Coal	3.90	2.89	2.71	2.45	2.10
Distillate Oil	.72	1.18	1.42	1.64	2.12
Residual Oil	2.21	3.17	3.60	4.13	4.66
Gas	4.00	6.77	8.42	10.40	12.12
TOTAL	10.83	14.01	16.15	18.62	21.00

TABLE 4-9

CALCULATED FUEL USE (QUANTITY UNITS)
U.S. TOTALS

	Fuel Consumption				
	1967	1975	1980	1985	1990
TOTAL BOILERS					
Coal (million tons)	358	567	785	913	1,107
Distillate Oil (million bbls)	503	640	761	835	1,021
Residual Oil (million bbls)	446	732	894	1,083	1,237
Gas (trillion cu ft)	9.54	15.20	17.55	23.72	28.14
INTERMEDIATE SIZE					
Coal (million tons)	150	111	104	94	81
Distillate Oil (million bbls)	124	204	245	283	366
Residual Oil (million bbls)	356	510	579	664	750
Gas (trillion cu ft)	4.00	6.77	8.42	10.40	12.12

industry [4-10,4-11,4-12]. Direct comparison of fuel projections for non-utility users (which group used large amounts of fuel in process applications) with the results discussed here was not possible, as this study was limited to fuel burned under boilers only. Thus, projected industrial fuel use in the conventional sense used in fuel use reporting would be much higher than the projections herein. The only direct comparison possible was for the electric utility industry, where practically all fuel is burned under boilers. The results of a comparison is summarized in Table 4-10.

In general, it is noted that the figures generated in this study are higher than most others. The projections herein are based on present fossil fuel trends, without consideration of the expansion of nuclear energy. At a later stage this source of energy can be included and new estimates can be made to determine the consequences. The basis for omission of nuclear generation was noted earlier.

If all boilers included in this study are considered, an upward trend in each of the fuel types consumed may be noted. Figure 4-10 shows the 1967 and 1990 market shares attributed to each fuel. The change in fuel shares over this period is small.

The total fuel use in 1990 is projected to be almost three times greater than that in 1967 (see Figure 4-11 and Table 4-8). As consumption of all fuels increases, air pollution emissions on an uncontrolled basis resulting from boilers would increase as well.

The intermediate-size boilers present a different picture. In spite of the increasing capacity and fuel use, SO_2 and particulates show a downward trend, and NO_x increases, but very slightly. The reason for this unexpected result may be found in the fuel use pattern projected for this class of boilers. Table 4-11 shows the fuel shares for this intermediate group (see also Figure 4-12), which change greatly over the period. The drastic decrease in coal use and a large increase in gas consumption results from the combination of the individual regional fuel projections, which shift would cause both the sulfur oxides and particulates

TABLE 4-10

UTILITY PROJECTIONS

Description	This Study	Other Sources	
Total Capacity 1980	4.02×10^6 pph	3.775×10^6 pph	[4-13]
		$3.147\text{-}4.436 \times 10^6$ pph	[4-6]
Total Fuel Use 1975	12.72×10^{15} Btu	11.4×10^{15} Btu	[4-14]
		11.0×10^{15} Btu	[4-6]
Total Oil 1975	1.80×10^{15} Btu	1.17×10^{15} Btu	[4-14]
		$.86 \times 10^{15}$ Btu	[4-6]
Total Gas 1975	4.85×10^{15} Btu	5.30×10^{15} Btu	[4-14]
		2.79×10^{15} Btu	[4-6]
Total Coal 1980	17.1×10^{15} Btu	14.3×10^{15} Btu	[4-14]
Total Oil 1980	2.35×10^{15} Btu	$.9 \times 10^{15}$ Btu	[4-14]
Total Gas 1980	6.42×10^{15} Btu	4.97×10^{15} Btu	[4-14]
Total Coal 1980	17.1×10^{15} Btu	$9.6\text{-}15.8 \times 10^{15}$ Btu	[4-6]
Total Oil 1980	2.35×10^{15} Btu	$.8\text{-}1.1 \times 10^{15}$ Btu	[4-6]
Total Gas 1980	6.42×10^{15} Btu	$2.5\text{-}5.8 \times 10^{15}$ Btu	[4-6]
Index 1990 Total Fuel (1970=100)	340	500	[4-15]
Total Gas 1990	10.01×10^{15} Btu	6.10×10^{15} Btu	[4-15]
Total Oil 1990	3.38×10^{15} Btu	3.92×10^{15} Btu	[4-15]

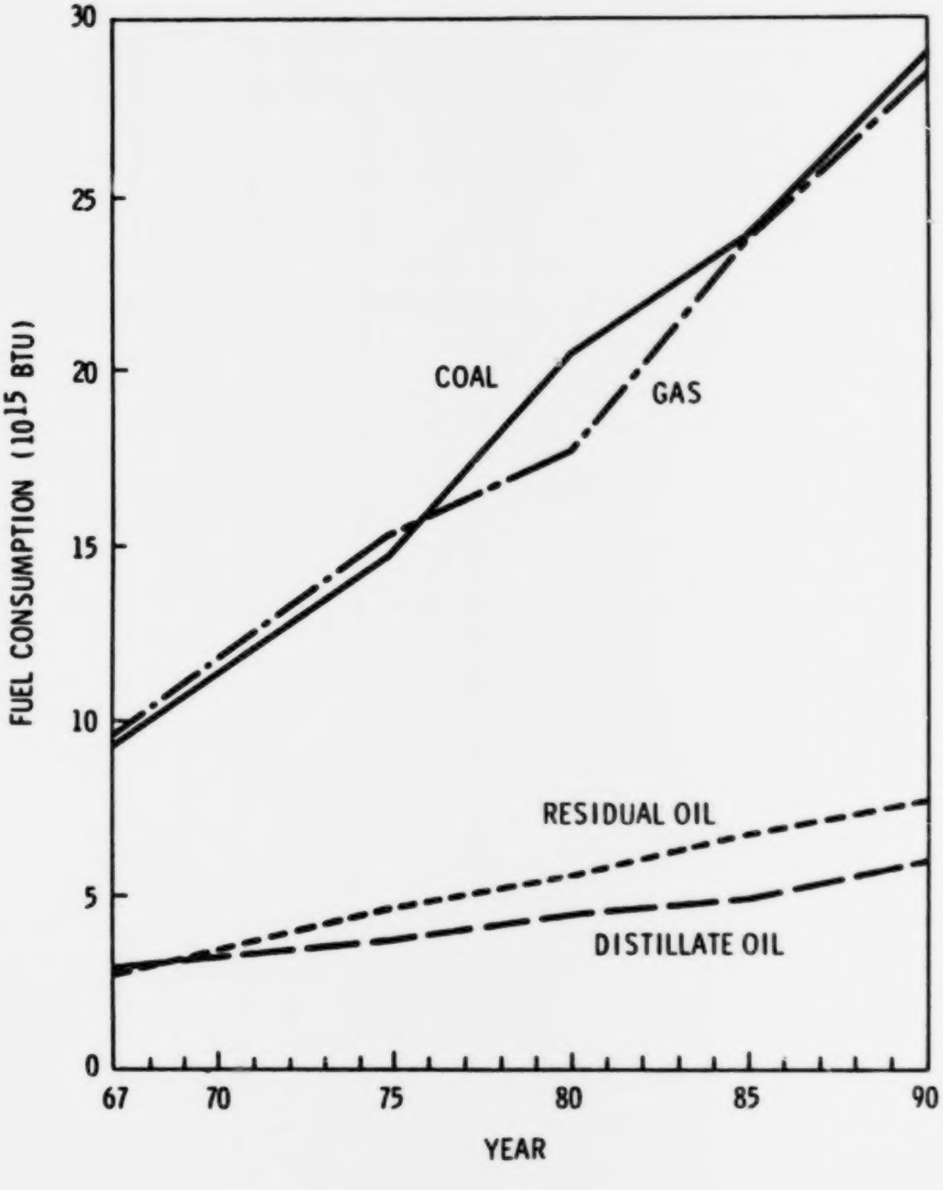


Figure 4-10. Projected Fuel Consumption - All Boilers.

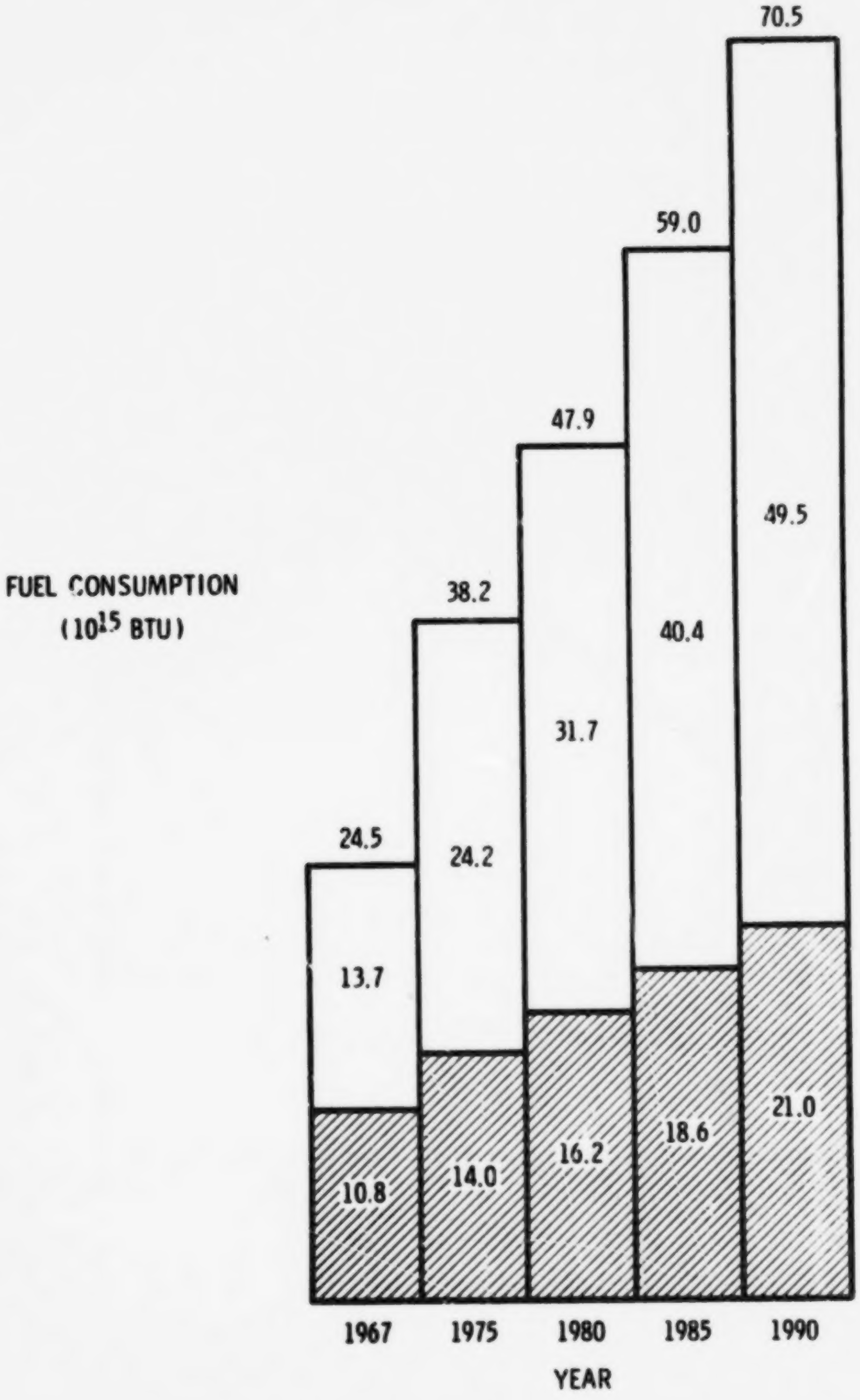


Figure 4-11. Fuel Consumption in Intermediate and in All Boilers.

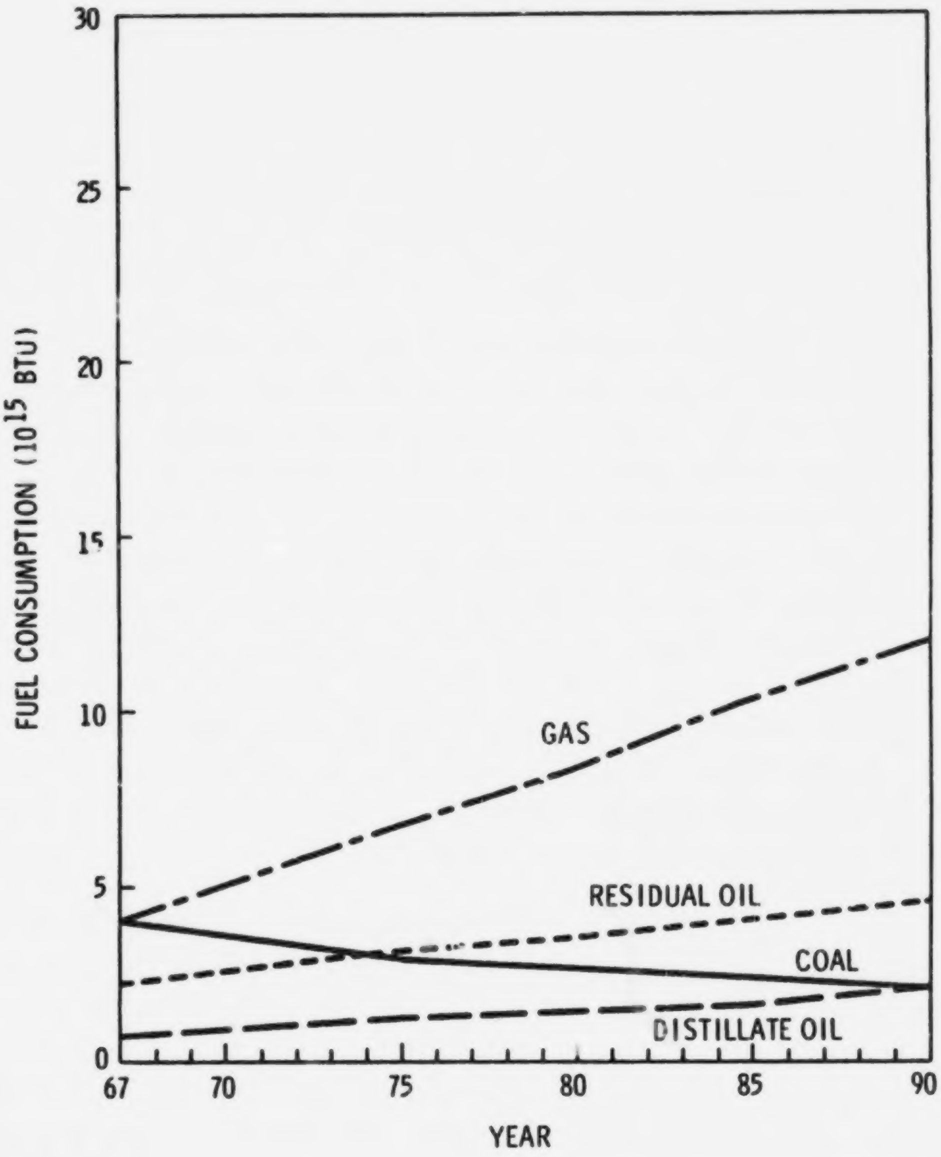


Figure 4-12. Projected Fuel-by-Fuel Consumption - Intermediate Boilers.

TABLE 4-11

NATIONAL FUEL SHARES (INTERMEDIATE-SIZE BOILERS ONLY)

	1967	1990
Coal	36%	10%
Distillate Oil	7%	10%
Residual Oil	20%	22%
Gas	37%	58%

emitted from these boilers to be less in the future, even in the absence of any controls. Present fuel trends, if fulfilled, i.e., if the supply can keep up with the demand, will tend to maintain emissions levels from the intermediate-size group at or less than present levels. Only the NO_x emissions from intermediate boilers increase a total of 37% between 1967 and 1990, which amounts to an average yearly growth of about 1.5%. The present trends indicate that commercial use of coal will be negligible by 1990. Commercial boilers represent 39% of the total capacity of intermediate boilers in 1967, and 45% in 1990. Also, coal use in industrial firetube and cast iron boilers is expected to be negligible by 1990. Thus, only the watertube boilers falling in the intermediate-size range will be burning coal by 1990. These boilers will be the main polluters in this size group at the end of the 20th century.

It is significant that in 1990 the fuel consumed by the intermediate-size group is almost as much as the fuel consumed by all boilers in 1967. If the fuel trends assumed as above do not materialize because of an inadequate supply of gas, as is generally feared today, the air pollution problem attributable to the intermediate group will be quite sizable. Therefore, the amount of fuel consumed in this category is very significant and the distribution of this total over the various fuel types may determine whether this group will be cause for extreme concern or not. Departures from the fuel trends as projected herein will greatly affect the results.

2. A Comparison of Calculated and Historical Fuel Use for 1967

An excellent check on the validity of the 1967 boiler inventory was the agreement found between the fuel consumption calculated (by STRAT) and the fuel use figures arrived at in an independent manner, which is described below. Utility usage for all fuels was taken from Steam-Electric Plant Factors - 1968 [4-2]. Data for the other user groups were obtained from a variety of sources.

a. Total Fuel Consumption in Stationary Sources

The coal figures presented in the 1967 Mineral Yearbook were used as follows: Retail Dealers sales were considered as commercial use. This interpretation was reconfirmed by Mr. W. J. Young who had been responsible for that section of the Mineral Yearbook [4-16]. The coal reported under All Others was considered as industrial. Coal converted to coke was not included in our figures. Residential coal use in 1967 was considered negligible.

The primary source of oil data is the Bureau of Mines Annual Fuel Oil Shipments Report [4-17]. Residential use of distillate oil was obtained by adding the total use of #1 heating oil and 90% of #2 heating oil. Commercial use of distillate oil was obtained by taking 10% of #2 heating oil and adding to this the #4 heating oil. Net industrial use of this fuel equals the industrial use reported by the Bureau of Mines minus the industrial use of diesel oil.

Since the residential category does not include apartment buildings, the residential use of residual oil was considered negligible. Commercial use of residual oil was obtained by taking a commercial fraction of the total residual type heating oils #5 and #6. This commercial fraction was computed for each state by dividing the number of employees in commercial establishments by the total number of employees in commercial and industrial establishments.

Industrial use of residual oil was obtained by taking an industrial fraction of the total residual type heating oils #5 and #6 and adding to it the industrial use of residual fuel oil as reported in the Fuel Oil Shipments Report [4-17]. This industrial fraction was computed for each state by dividing the number of employees in industrial establishments by the total number of employees in commercial and industrial establishments.

Residential and commercial use of gas were reported as such in the 1967 Mineral Yearbook by state.

Industrial totals were obtained by taking the total industrial figures and subtracting the totals for utilities, pipelines, and field use, all reported in the Mineral Yearbook by state. For Kansas, Louisiana, Oklahoma, Texas, New Mexico, and California, these data were adjusted further by subtracting the amount of natural gas used for raw materials. Respectively, 5, 34, 8, 43, 6, and 4 percent were allocated by using the marketed production in these states as shown in the Mineral Yearbook.

The fuel data thus obtained were based on total consumption in all types of equipment. The distribution of the total consumption by user and fuel is shown in Figure 4-13.

b. Fuel Burned under Boilers

An allocation of each fuel class according to that fraction burned under those boilers and warm air furnaces conforming to the conventional definition used herein has been made to separate boiler fuel from that burned in all other equipment such as non-central heating, cooking, industrial furnaces, kilns, etc. The following discussion summarizes the rationale used in making the allocation. It was necessary to estimate the percentage of each fuel burned under boilers according to major user.

First, estimates of the percentages of fuel burned under industrial boilers were obtained by estimating, for each major SIC category, typical use patterns for each fuel. Results are given in Table 4-12. Data for the primary metals class were derived from the AISI Annual data summary, and were assumed to be representative of all primary metals fuel

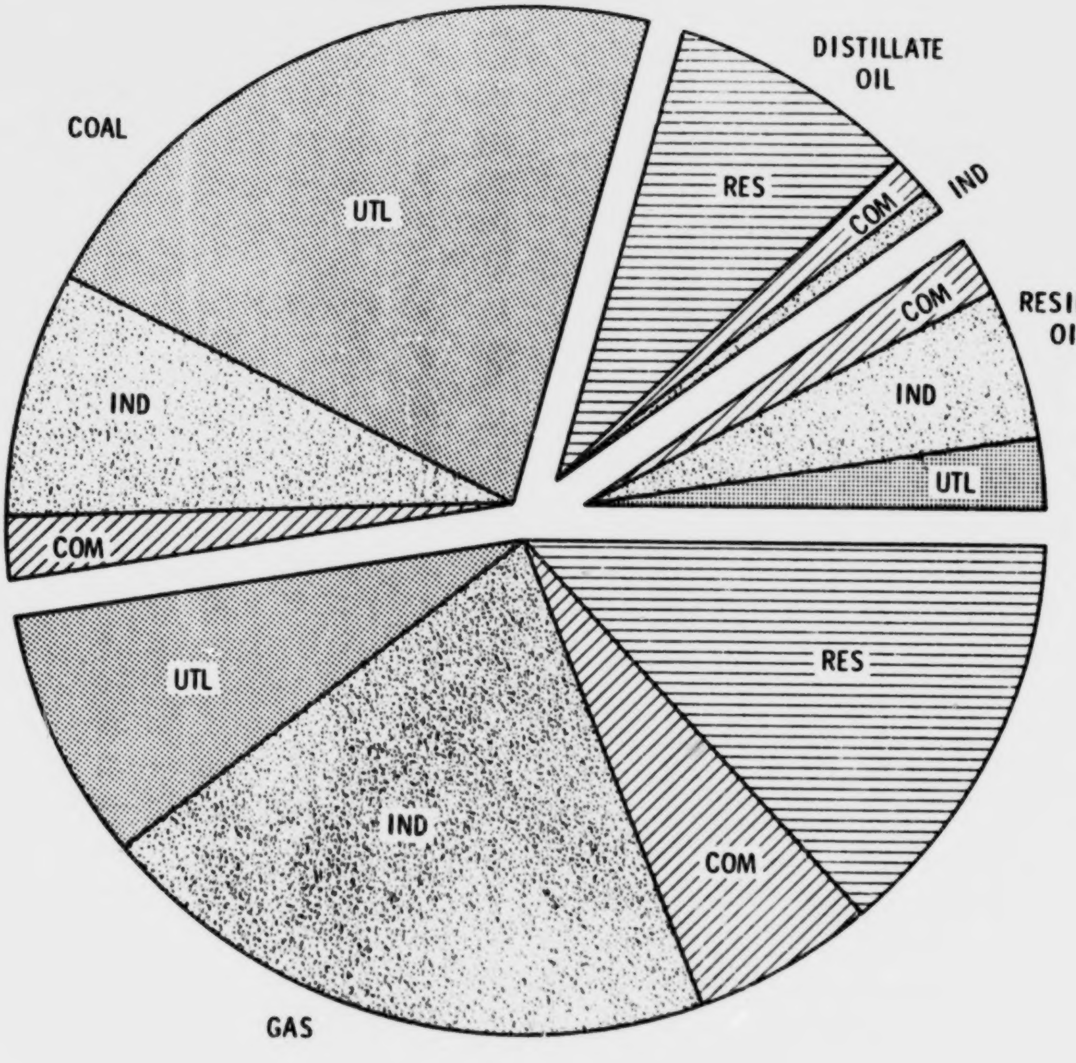


Figure 4-13. 1967 Total Fuel Consumption by Fuel and User.

TABLE 4-12

PERCENTAGE OF FUEL IN MANUFACTURING USED IN BOILERS

Industry	Percent Burned under Boilers		
	Coal	Oil	Gas
Food	100	100	90
Tobacco	100	85	50
Textile	100	90	80
Apparel	100	90	80
Lumber	100	90	70
Furniture	100	90	50
Printing	100	90	85
Chemicals	75	40	30
Petroleum	90	40	30
Rubber, Plastics	100	65	40
Leather	100	85	50
Stone, Clay, Glass	10	10	10
Fabricated Metal	90	70	20
Machinery	90	70	20
Elec. Machinery	90	70	20
Transp. Equipment	90	80	20
Instruments	90	80	45
Primary Metals	90	10	10
Paper	100	95	93
Miscellaneous	70	50	50
Weighted Average	77	55	30

use [4-18]. The estimate for stone, clay and glass was obtained from an AGA report on future energy requirements which contained a breakdown of fuel practices in that industry [4-19]. The paper industry figure was based on Walden experience in pulp and paper mill engineering. The remaining values were estimated through rough engineering calculations and examination of industry flow sheets where available.

The major fuel users are primary metals, chemicals, petroleum, and paper. For these users, the estimates are based on a reasonably factual basis. As a result, the overall estimates for industrial use of fuel under the boilers appear to be valid and useful within the constraints of this study.

Percentages for other users were derived as follows:

Coal

It was assumed that 100% of the coal burned by commercial users is burned in boilers. Engineering estimates made of the percentage of the coal used in boilers in each industrial-manufacturing group (see Table 4-12) resulted in a figure of 77%. It was assumed that 100% of the coal burned by utilities is burned in boilers.

Gas

A regression analysis was performed on estimated sales of gas for residential space heating, using historical data for 1949-1960 [4-20]. The following linear relationship resulted (units in 10^9 Btu):

$$\text{Space heating} = 0.7 \times \text{total sales} - 217{,}300 \qquad (4\text{-}2)$$

This regression showed a multiple correlation coefficient of .99 and very significant F and t statistics. The standard error of the dependent variable was small. Using this equation to predict the use of gas for space heating in 1967 resulted in a total of 2,802,048 million cubic feet, i.e., 64.9% of the total residential gas used. From telephone interviews with several gas companies across the country, it was determined that percentages for space heating ranging from 60 to 75 percent were reasonable. The value of 65 percent was used for gas residential space heating. The balance is used for cooking, hot water, air conditioning, etc.

Petroleum Facts and Figures 1967 reports 18,184,321 domestic central heating gas burners in use in 1967 [4-21]. Gas Facts 1968 reports 31,085,000 housing units using gas heat in 1967 [4-22].

From these two figures it was concluded that approximately 58.5% of the space heating by gas takes place in central heating equipment. In other words, about 38% of the total residential use of gas is burned in central heating equipment.

The percentage of commercial gas burned in central heating equipment was set at 50%, a slightly higher percentage than that for residential central heating consumption. In the same way as for coal, estimates were made by manufacturing group of the percentage of the gas used in each group which would be burned in boilers (see Table 4-12). The overall weighted industry use of gas in boilers was estimated at 30%. It was assumed that 100% of the gas burned by utilities is burned in boilers.

Oil

Petroleum Facts and Figures 1968 reports 10,692,825 domestic central heating oil burners in use in 1967 [4-21]. The average use of oil per burner per year was found to be approximately 1500 gallons. This is equivalent to the consumption of 381,700 thousands of barrels or 87.7% of the total residential oil in central heating equipment. The percentage of commercial distillate and residual oil burned in central heating equipment was set at 90%, a slightly higher percentage than that for residential central heating consumption. In the same way as for coal and gas, estimates were made by manufacturing group of the percentage of oil used in each group which would be burned in boilers (see Table 4-12). The overall weighted industry use of oil in boilers is 55%. This result was adjusted to account for the following factors.

The industrial category used by the BuMines includes non-manufacturing industries such as mining, agriculture. The percentage of fuel used by those companies classed as manufacturers (SIC codes 19-39) amounts to only about two thirds of the total industrial oil consumption. Since manufacturing industrial users will require mainly space heating or process steam, it was assumed that the remaining one third was burned entirely under boilers. Weighting these percentages resulted in an estimate that 70% of the total industrial oil is burned under boilers. It is assumed that 100% of the oil burned by utilities is burned under boilers.

The various percentages are summarized in Table 4-13. The results are shown in Table 4-14 and Figure 4-14. The relative usage of gas in boilers is markedly lower than the overall use of gas in stationary sources due to the large use of gas in industrial processes and in other applications. Coal-burning utilities dominate the picture. Note that these sectors represent relative, not absolute, contributions and that pollution from the combustion of fuel will occur even if consumed in equipment other than boilers.

TABLE 4-13

PERCENT OF FUEL BURNED IN BOILERS
ACCORDING TO USER

	Percent of Fuel Burned in Boilers			
User	Coal	Distillate Oil	Residual Oil	Gas
Residential	--	88	--	38
Commercial	100	90	90	50
Industrial	77	70	70	30
Utility	100	--	100	100

TABLE 4-14

ANNUAL FUEL BURNED UNDER BOILERS

BY FUEL		
COAL	(thousands of tons)	(10^{12} Btu)
Commercial	18,298	476
Industrial	72,906	1,896
Utilities	273,189	7,103
TOTAL COAL	364,393	9,475
DISTILLATE OIL	(thousands of barrels)	
Residential	381,669	2,324
Commercial	56,300	343
Industrial	17,961	109
TOTAL DISTILLATE OIL	455,930	2,776
RESIDUAL OIL	(thousands of barrels)	
Commercial	91,574	558
Industrial	170,071	1,036
Utilities	149,182	909
TOTAL RESIDUAL OIL	410,827	2,503
GAS	(million cubic feet)	
Residential	1,639,056	1,639
Commercial	858,276	858
Industrial	1,982,841	1,983
Utilities	2,655,870	2,656
TOTAL GAS	7,136,043	7,136
TOTAL ALL FUELS		21,890
BY USER		
Residential		3,963 (18%)
Commercial		2,235 (10%)
Industrial		5,024 (23%)
Utility		10,668 (49%)
TOTAL ALL FUELS		21,890 (100%)

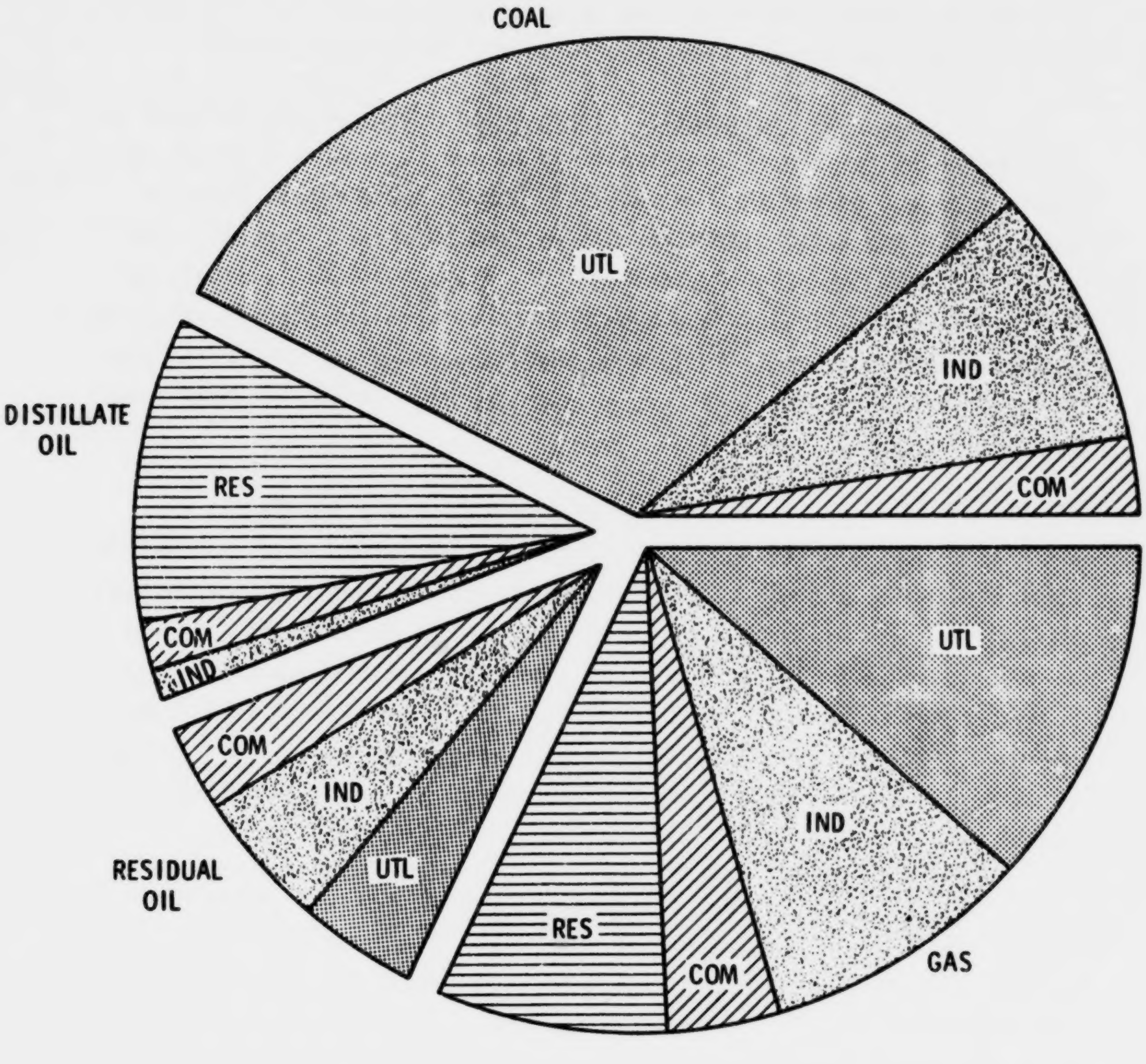


Figure 4-14. 1967 Fuel Consumption in Boilers By Fuel and User.

c. Fuel Use Comparison

The figures derived as above were compared to the fuel consumption figures resulting from calculation procedure in STRAT based on installed capacity and operating factors. The results follow:

(1) Residential (Table 4-15) - The calculated total gas consumption by residential users differs by only 1 percent from the consumption of gas burned in home heating. The Atlantic region value is quite high. The total distillate oil differs by about 7 percent. The South East value is slightly too low. The overall results are very satisfactory, especially when one considers that the STRAT figures are being compared with an estimate of fuel used for space heating only. The difference between the two total Btu consumption figures in this user category is only about 2 percent.

(2) Commercial (Table 4-16) - The STRAT totals are about 9 percent higher than the estimate of fuel burned under boilers in commercial establishments. The individual coal figures are significantly too high for the Atlantic, the South East and the Rural North. It was decided to leave this discrepancy unchanged. Since the overall methodology appears to have produced such reasonable overall results, it was believed that little improvement could be introduced by trying to force-fit a fuel match for each region without a rational motive or sample to back up such change.

(3) Industrial (Table 4-17) - The STRAT totals for industry are about 13 percent higher than the estimate of fuel burned under boilers in industry. The difference is distributed about equally over the four fuels. Again, it was believed that the difference was not significant enough to require changes which would reduce the value of the methodology used to obtain the boiler inventory.

(4) Utilities (Table 4-18) - The STRAT totals for total fuel use by the utility industry in 1967 and those available from Steam and Electric Plant Factors were essentially in exact agreement [4-2].

TABLE 4-15

RESIDENTIAL

FUEL CONSUMPTION IN BOILERS IN 10^{15} Btu

	GS		RO		DO		CL	
	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT
AT	.721	.859	None		1.252	1.225	None	
GL	1.017	.988	None		.479	.377	None	
WS	.678	.652	None		.114	.133	None	
CU	.507	.466	None		.163	.136	None	
SE	.261	.277	None		.107	.065	None	
RN	.045	.032	None		.105	.129	None	
	3.229	3.274	None		2.220	2.065	None	

Fuel Total = 5.45×10^{15} Btu

STRAT Total = 5.34×10^{15} Btu

TABLE 4-16

COMMERCIAL

FUEL CONSUMPTION IN BOILERS IN 10^{15} Btu

	GS		RO		DO		CL	
	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT
AT	.227	.145	.470	.460	.231	.223	.053	.134
GL	.396	.329	.053	.076	.050	.064	.281	.263
WS	.298	.550	.032	.049	.009	.012	.008	.006
CU	.252	.268	.012	.014	.014	.010	.046	.058
SE	.127	.102	.009	.014	.011	.009	.069	.105
RN	.037	.039	.006	.030	.012	.017	.023	.042
	1.339	1.383	.585	.643	.327	.335	.479	.608

Fuel Total = 2.730×10^{15} Btu

STRAT Total = 2.969×10^{15} Btu

TABLE 4-17

INDUSTRIAL

FUEL CONSUMPTION IN BOILERS IN 10^{15} Btu

	GS		RO		DO		CL	
	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT
AT	.176	.104	.663	.669	.0409	.204	.487	.603
GL	.393	.416	.148	.162	.0245	.081	.909	.923
WS	.979	1.024	.140	.243	.0206	.0168	.026	.0215
CU	.248	.296	.051	.031	.0058	.008	.131	.170
SE	.238	.194	.068	.070	.0078	.0016	.337	.399
RN	.027	.035	.015	.051	.0047	.016	.024	.067
	2.061	2.069	1.085	1.226	.104	.348	1.914	2.183

Fuel Total = 5.164×10^{15} Btu

STRAT Total = 5.826×10^{15} Btu

TABLE 4-18

UTILITIES

FUEL CONSUMPTION IN BOILERS IN 10^{15} Btu

	GS		RO		CL	
	Fuel	STRAT	Fuel	STRAT	Fuel	STRAT
AT	.126	.039	.607	.652	1.760	1.703
GL	.087	.103	.003	.031	2.362	2.208
WS	1.821	1.967	.315	.243	.083	.117
CU	.582	.614	.011	.026	.410	.466
SE	.142	.129	.003	.024	1.841	1.811
RN	.004	.016	.013	.020	.110	.111
	2.758	2.868	.952	.996	6.567	6.416

Fuel Total = 10.28 x 10^{15} Btu

STRAT Total = 10.29 x 10^{15} Btu

The individual fuel totals are within 5 percent of the fuel figures reported by the FPC. This result lends credibility to the whole study, since the FPC data are accurate and can be essentially entirely accounted for as fuel burned under boilers.

It is noted that those individual entries in Tables 4-15 to 4-18 which differ from fuel data by large percentages are generally minor items, i.e., distillate oil use for industry, residual oil use for utilities, and all fuels for the Rural North region in general. Since these small quantities of fuel do not represent significant sources of pollution to be controlled, this fact should not make the results less significant.

REFERENCES TO SECTION IV

4-1. Statistical Yearbook of the Electric Utility Industry for 1967, Edison Electric Institute, New York, 1968.

4-2. Steam-Electric Plant Factors, National Coal Association, Washington, D.C., 1968.

4-3. "Cost of Clean Air," First Report of the Secretary of Health, Education and Welfare to the Congress of the United States on the Air Quality Act of 1967, June 1969.

4-4. Bartok, et al., "Systems Study of NO_x Control Methods for Stationary Sources," Esso R&D Co. (NAPCA Contract PH 22-68-55), November 1969.

4-5. Sherwood, T. K., "Must We Breathe Sulfur Oxides," Technology Review, January 1970.

4-6. Morrison, W. E. and Readling, C. L., "An Energy Model for the United States," U.S. Bureau of Mines, Information Circular 8384. Washington, D.C., 1968.

4-7. Crawford, A. R. and Bartok, W., "Survey of NO_x Emissions in U.S. with Projections to the Year 2000," presented at Annual APCA Meeting, June 1969.

4-8. Devitt, T., "Particulate Systems Study," Midwest Research Institute Quarterly Report No. 2, CPA 22-69-104, September-December 1969.

4-9. "Fly Ash Still Piling Up," Chemical Engineering, April 20, 1970.

4-10. Brown, W. D., "20th Annual Electrical Industry Forecast," Electrical World, September 15, 1969.

4-11. Fremont, F., "Annual Growth Rate on Downward Trend," Electrical World, July 6, 1970.

4-12. "National Power Survey, Parts I and II, Federal Power Commission, Washington, D.C., 1964.

4-13. Vogely, W. A. and Morrison, W. E., "Patterns of U.S. Energy Consumption to 1980," IEEE Spectrum, September 1967.

4-14. Electrical World, pp. 30-32, September 6, 1969.

4-15. Combustion, pp. 8-12, April 1970.

4-16. Minerals Yearbook 1967, Volumes I-II, U.S. Bureau of Mines, 1967.

REFERENCES TO SECTION IV (continued)

4-17. Mineral Industry Surveys, Annual "Shipments of Fuel Oil and Kerosene," U.S. Bureau of Mines, 1967.

4-18. "Annual Statistical Report," American Iron and Steel Institute, 1968.

4-19. "Process Energy Requirements in the Ceramics Industry," and "Process Energy Requirements in the Glass Industry," American Gas Association, Inc.

4-20. Historical Statistics of the Gas Industry, American Gas Association, Inc.

4-21. Petroleum Facts and Figures, American Petroleum Institute, 1967.

4-22. 1968 Gas Facts, American Gas Association, Inc., New York.

V. STRATEGIES FOR EMISSION ABATEMENT

A. INTRODUCTION

The development of an inventory of boiler equipment and fuel by various categories and then the derivation of combustion emissions and projections has been presented and discussed. Attention is now directed to possible means to control these emissions. In general, some methods are effective by preventing or reducing the formation of certain pollutants, where others work to remove from the flue gases undesirable products of combustion that were generated in the boiler.

Considered in sequence below are the following broad groups:

(1) Fuel switching to reduce formation of particulates, SO_2 and NO_x during combustion
(2) Mechanical methods for removal of particulates from flue gas
(3) Chemical process controls for removal of SO_2 (and NO_x) from flue gas
(4) Changes in combustion design to reduce formation of particulates and NO_x

The evaluation of control means, singly or combined into broad-based strategies, requires inputs relevant to the overall applicability of the approaches to the various boiler types, the state of development of the approach, and specific operating and cost data. This section of the report presents such data pertinent to each of the major classes of potential control approaches. The next section, VI, of the report presents the conclusions of the evaluation process and the selection of the most cost-effective routes to follow for effective abatement of emissions from intermediate-size boilers.

B. FUEL SWITCHING

1. General Approach

The parameters of fuel switching are well known and do not warrant explanation in great detail. Without restriction of cost, availability or boiler design, the following generalizations can be employed as guidelines in examining possibilities of fuel switching:

a. Natural gas, now and in the foreseeable future, is the closest approach to a perfect fuel; very low in particulate and SO_2 emissions; not nearly so advantageous in NO_x emission, but better than other fuels in most cases.

b. Distillate oil is lowest of all liquid fuels considered with respect to particulates, SO_2 and NO_x emissions, but for each pollutant somewhat higher than gas.

c. Low-sulfur residual oil and residual oil are considered equal in emissions factors for particulates and NO_x, but differ by a factor of about 4 to 5 with respect to sulfur content and, therefore, in SO_2 emissions. The emission of all three pollutants is greater than for the above fuels.

d. Coal has generally the highest pollutant potential of any fossil fuel with respect to particulates, SO_2 and NO_x, when uncontrolled. Even with particulate control equipment, it still may rank highest in this category.

Two other fuels were not given consideration:

e. No. 4 oil ranks between distillate (No. 2) and residual (No. 6) in virtually all aspects: price, sulfur content and, thus, SO_2 emissions, handling characteristics, heating value, etc. However, it is not commercially available on a wide scale (usually restricted to commercial or small industrial users, i.e., large firetube and small watertube boiler operators) and, therefore, was not included in this study.

f. Low-sulfur coal has the same principal characteristics as other coals except that its SO_2 emissions will obviously be lower. It is found in limited quantities in the major coal-mining states where most of it is owned by the steel companies and used by them because of its unique qualifications as so-called "metallurgical" coal. Except for minor amounts, it is not available as boiler fuel -- and, indeed, is usually considered too valuable as a special resource to be so used. There is a second source consisting of enormous quantities of low-sulfur sub-bituminous coal and lignite in the north central states (the Rural North region). This fuel often has a lower heating value and high ash and requires a somewhat different boiler design; however, the magnitude of the resource (which will result in a low cost) and its low sulfur make it a valuable future fuel -- future, because it is distant from all major centers of population and steam generation. Thus, this fuel was also excluded from the study as a separate alternative fuel.

Application of fuel switching for various combinations of fuel pairs and subsets of boilers was effectuated through use of the STRAT computer program. The STRAT program contains all the necessary information regarding fuel prices and emissions factors to generate the important quantitative results of a fuel switch so that cost-effectiveness judgments could be made. Examples of specific combinations included switches on certain groups of coal-fired boilers to distillate or to residual or to low-sulfur residual or to gas or to a combination of these fuels according to region. Another run would limit the switch to units less than 20 years old, etc. A summary of the specific combinations is contained in Appendix C.

2. Fuel Prices

Table 5-1 shows the price in dollars per million Btu of various fuels according to the user category and region. These are 1967 prices based on data in Fuel in Fifty Cities by Ernst and Ernst for commercial and industrial users [5-1]. Those data, reported by city, were lumped to obtain regional prices needed in this study. Where bias would be introduced through weighing on a population or usage basis, corrections were made to obtain more realistic estimates. Thus, for example, it was found that Florida was over-represented in the Ernst and Ernst report. Because of this, the Far West and South regional prices would be too large due to the high fuel prices in Florida. Necessary adjustments were made for such cases.

TABLE 5-1

FUEL RATES
(1967 Basis)

Region	Gas (I)	Gas (F)	Residual Oil S<.5	Residual Oil S≤1.	Residual Oil S>1.	Distillate Oil	Coal S≤1.	Coal S>1.
USER GROUP IS COMMERCIAL								
AT	0.57	1.36	0.74	0.66	0.51	1.08	1.02	0.78
GL	0.53	0.84	0.78	0.70	0.68	1.04	0.79	0.57
WS	0.41	0.80	0.74	0.66	0.46	1.02	0.97	0.75
CU	0.47	0.67	0.67	0.59	0.54	0.98	0.65	0.52
SE	0.46	0.67	0.75	0.67	0.47	0.99	0.63	0.49
RN	0.48	0.94	0.74	0.66	0.50	1.03	0.88	0.68
USER GROUP IS INDUSTRIAL								
AT	0.45	1.03	0.59	0.51	0.40	0.84	0.43	0.37
GL	0.38	0.58	0.62	0.54	0.53	0.81	0.38	0.34
WS	0.37	0.52	0.63	0.55	0.37	0.79	0.50	0.38
CU	0.28	0.54	0.53	0.45	0.42	0.76	0.45	0.38
SE	0.36	0.50	0.63	0.55	0.37	0.77	0.36	0.35
RN	0.37	0.70	0.58	0.50	0.40	0.80	0.46	0.38
USER GROUP IS UTILITY								
AT	0.35	0.35	0.40	0.32	0.32	0.84	0.29	0.29
GL	0.27	0.27	0.72	0.64	0.64	0.81	0.25	0.25
WS	0.25	0.25	0.40	0.32	0.32	0.79	0.23	0.23
CU	0.22	0.22	0.39	0.31	0.31	0.76	0.26	0.26
SE	0.24	0.24	0.55	0.47	0.47	0.77	0.23	0.23
RN	0.27	0.27	0.39	0.31	0.31	0.80	0.20	0.20

I = Interruptible
F = Firm
Data in $\$/10^6$ Btu

Regional prices for fuel used by electric utilities were obtained from cost figures in 1968 Steam and Electric Plant Factors [5-2]. Cost per million Btu was available on a state-by-state basis. Weighted averages were computed for the fuel prices in each of the six regions involved in this study. The prices calculated in this way for oil were assumed to apply to residual oil containing at least 1% sulfur. Residual oil requiring desulfurization to obtain a maximum of .5% sulfur was assumed to cost an average of 8 cents per million Btu (equivalent to about 50 cents per barrel) more than 1% sulfur residual oil [5-3].

The calculated high sulfur oil prices showed great variations. They ranged from $.31 for the Rural North to $.64 for the Great Lakes region. It appears that in the regions where the calculated prices of oil is extraordinarily high, very little oil is used by utilities. Oil is used mostly to meet peak demands in these areas, and at such times even distillate oil may be used. Such sporadic demands are necessarily fulfilled at high prices, which would not be representative in case of a more regular demand. If, for example, all the utilities in the Great Lakes region would switch to oil, the price of oil would go down to a more competitive level. Thus, oil for industrial use is competitively priced in the Great Lakes region.

It was assumed that the coal prices for utilities referred mostly to high sulfur coal. Note that the Rural North has a low coal price. This is a result of the use of local supplies of low grades in the north central states. Coal prices in the New England portion of Rural North states would most certainly be higher.

3. Fuel Availability

The problem of fuel supply-demand behavior was not a part of this study as such. It was necessary to look into this matter briefly in order to arrive at meaningful strategies. It was decided that all fuel-switching strategies would be expressed in the 1967 prices discussed above. It was believed that projecting price increases for future years would be practically impossible on as broad a scale as used here, since it would involve qualitative judgment on such matters as import restrictions, political stability in the Mideast and South America, domestic price restrictions, etc. It would furthermore mean using a supply and demand model, which is not available. Consequently, the fuel costs used in the switching strategies are presumably lower than they would be in reality.

The impact of the various fuel strategies on the demand for gas and oil is discussed in Section VI, below. Any factor tending to stabilize fuel costs at current levels in the face of sharply increased demand would support fuel switching as a national strategy. An increase in the supply of gas is such a factor.

Increases in gas supply could be achieved by:

(1) Discovery of new domestic gas field and improvement of productivity of present operating fields

(2) Importation of LNG

(3) Coal gasification

4. Capital Costs Involved in Fuel Switching

There has been much evidence in recent years of the increasing pace of conversion of boiler fuel -- from coal to oil and/or gas and perhaps to a lesser extent from oil to gas. This has been reported by fuel associations, boiler and burner manufacturers, and government data on fuel consumption. The pattern across the country has varied in proportion to the dependence on coal in a given region, and the aggressiveness with which oil and gas have been marketed in that region.

Perhaps the factor that can introduce the largest variable in the economics of fuel switching is the age, condition and type of the coal firing equipment. Large numbers of boilers have been converted since World War II, with hardly a thought to pollution, purely for reasons of economy. These were coal-fired units with outmoded stokers requiring high maintenance and a large operating crew -- or even hand-fired boilers. Economic evaluation of existing vs conversion often showed an attractive pay-back on the investment.

Consideration of fuel switching in this study cannot be based on those units where economy governs due to fuel cost or equipment operation. It is assumed that the inventory of boilers in STRAT considered for switching are in good operating condition and that the only reason for fuel switching would be to gain the advantage of reduced emission factor.

The cost of operation of converted equipment with a fluid fuel rather than solid fuel is the sum of the annualized capital cost and the annual operating cost. The latter, in turn, is comprised of fuel cost, labor and maintenance expenses. While it is virtually certain that labor and maintenance after conversion to fluid fuel must be less than for the replaced coal installation, the equivalent cost is likely to be small in comparison to the cost of fuel itself. It is also very variable and difficult to arrive at an acceptable average or typical figure in terms of savings per million Btu or thousand pounds of steam. Also, the coal burning equipment, in most cases, will have been largely written off with respect to capital cost whereas new equipment will carry with it an amortization burden. Covered in this section is the capital cost of conversion. This consists of (1) new equipment and alterations at the furnace for satisfactory combustion of the fuel and (2) storage, handling, pumping and piping of the fuel.

The capital costs developed below were converted into an annual basis assuming a useful life of 20 years. Inclusion of the cost of money, taxes, insurance, etc., results in annualization at the rate of 14.3% of capital cost.

a. Costs at the Furnace

There appears to be no limit on the types of coal burning installations which can be replaced by gas/oil burners, assuming the age and condition of the existing unit is such that a new package type boiler would not be a more practical replacement.

On small underfeed stokers such as side dump, the gas/oil firing equipment can be readily positioned through the opening for a ram or a fire door. The stoker would be removed.

On larger underfeed stokers such as multiple retort type, the refractory wall on front of the unit can be rearranged for installation of gas/oil burners. The only limitation seems to be choice of burner to fit combustion chamber. There are small burner manufacturers who make gas burners having an arrangement of gas ports giving very short burnout distance for this application.

On larger stokers such as overfeed and spreader stokers from 50,000 pph and up with straight gas firing, furnaces are often adaptable to the intertube burners through a sidewall. With wide tube spacing, no pressure parts need be affected because gas ports fire between tubes. The stoker may be simply covered with ash or refractory, or completely removed.

If oil firing is anticipated as alternate fuel with gas, then a circular burner is recommended. If circular burners are preferred, either for combination gas/oil firing or straight gas or oil firing, there are various arrangements possible. Where the existing front wall is refractory up to the feeder hoppers, burners can be installed without affecting pressure parts. There are conditions of furnace arrangement where burners through the side walls are recommended by boiler manufacturers; rearrangement of furnace water-wall tubes then becomes necessary.

Conversion of pulverized coal burners requires the least expenditure because this type burner has been designed to include various alternate fuel firing. This is true with circular, tangential and cyclone type burners. Changing to gas/oil firing includes the cost of adding a gas gun or oil gun through an existing register or burner, plus connecting the fuel lines and adding some flame protection controls.

Table 5-2 summarizes the costs by type of conversion and capacity [5-4].

(1) Underfeed Stokers

These units are separated into the small side dump stokers up to 15,000 pph and the multiple retort underfeed stokers for

TABLE 5-2

COSTS OF CONVERTING FROM COAL FIRING TO GAS/OIL

Capacity of Unit pph Steam	Approximate Cost of New Boiler*	Underfeed Stokers		Overfeed and Spreader Stokers	Pulverized Coal
		Side Dump	Multiple Retort		
15,000	$ 90,000	$12,500			
25,000	150,000		$22,000		
50,000	250,000		30,000		
75,000	300,000			$ 73,000	
100,000	400,000			83,000	
150,000	600,000			97,000	$50,000 (3 Burners)
200,000	700,000			125,000	
250,000	750,000			145,000	60,000 (4 Burners)
300,000	900,000				
350,000	1,050,000				
400,000	1,200,000				80,000 (6 Burners)

---

*The approximate cost of a new installation includes boiler and auxiliaries, foundation, piping and other costs, but not fuel supply costs, tanks, steam coils, etc.

capacities up to 50,000 pph. There can be various types or combinations of fuel used and number of burners to suit the furnace configuration or steam demands. Assuming gas and heavy oil to be fired, package type burners are available including complete burner with throat tile, flame protection, burner controls, fans, and pump-heater-strainer sets. For the units up to 15,000 pph, a single package burner would be the most practical application. Cost of this burner would be approximately $10,000. Adding 20% for contingencies, including a small amount of piping, electrical connections, and adapting to furnace opening, would increase the estimated cost to $12,000. If this package assembly were to fire natural gas only, the price would reduce to $7,200.

If the original fan is large enough, then a separate purchase of burner registers, gas and oil guns, flame protection, burner controls, oil pump-heater set, and ductwork would cost about $10,000; for gas alone, the figure would be about $6,200.

On units from 15,000 pph to 50,000 pph capacity, two burners would be more practical for the greater width, shorter depth furnaces with multiple retort underfeed stokers. Relatively more work would be required to remove coal burning equipment on the front furnace wall and for adaptation of burners to front refractory wall. Using package-type burners, estimated cost of converting would be $30,000 for two burners firing gas/heavy oil or approximately $20,000 for straight gas firing at 50,000 pph. For smaller units at 20,000 pph, the estimated cost for gas/heavy oil conversion would be $22,000 and, for gas firing only, about $14,000.

(2) Overfeed - Spreader Stoker Firing

Cost for changing to complete circular type gas/oil burners over these type stokers must take into consideration the construction and arrangement of the front furnace wall, cross sectional area of the furnace at the proposed burner level, and extent of pressure part alteration. Examples for a range of sizes are as follows:

75,000 pph spreader-stoker fired boiler -- field alterations include removing stoker and front refractory wall under header, adding support steel with refractory bottom to permit removal of stoker, and adding ductwork to two circular burners in the front wall. Approximate cost is $53,000, including material price of $22,500 for gas/oil burners, burner windbox, refractories, insulation, structural steel and floor plates. Not included are fuel piping to burners, combustion controls or flame protection equipment. The estimated additional cost for these components is $20,000, resulting in a total cost of $73,000 for material and labor.

The same type installation for a 100,000 pph unit with three burners is estimated at $63,000, which, with an additional $20,000 for piping and flame failure system, would total approximately $83,000. A similar installation for a 150,000 pph unit with three burners would total approximately $97,000.

(3) Pulverized Fuel Burners

For a completely engineered and installed gas/oil conversion, including gas gun, ignitor, flame protection, burner controls and oil pump-heater set, cost would be $15,000 per burner. Burner capacity, in this range of boiler sizes, is assumed to be from 50,000-70,000 pph each.

b. Costs for Fuel Handling Equipment

Costs taken from actual installations have been used to develop the curves shown in Figure 5-1 [5-5]. At the low end of the capacity range indicated, the fuel is #2 oil which requires only tanks for storage, pumps and piping. At greater capacities, the fuel is #6 oil, for which there is the additional requirements of heaters, both in the storage tank and near the burners to condition the oil for pumping, proper atomization and combustion by elevation to an adequate temperature level.

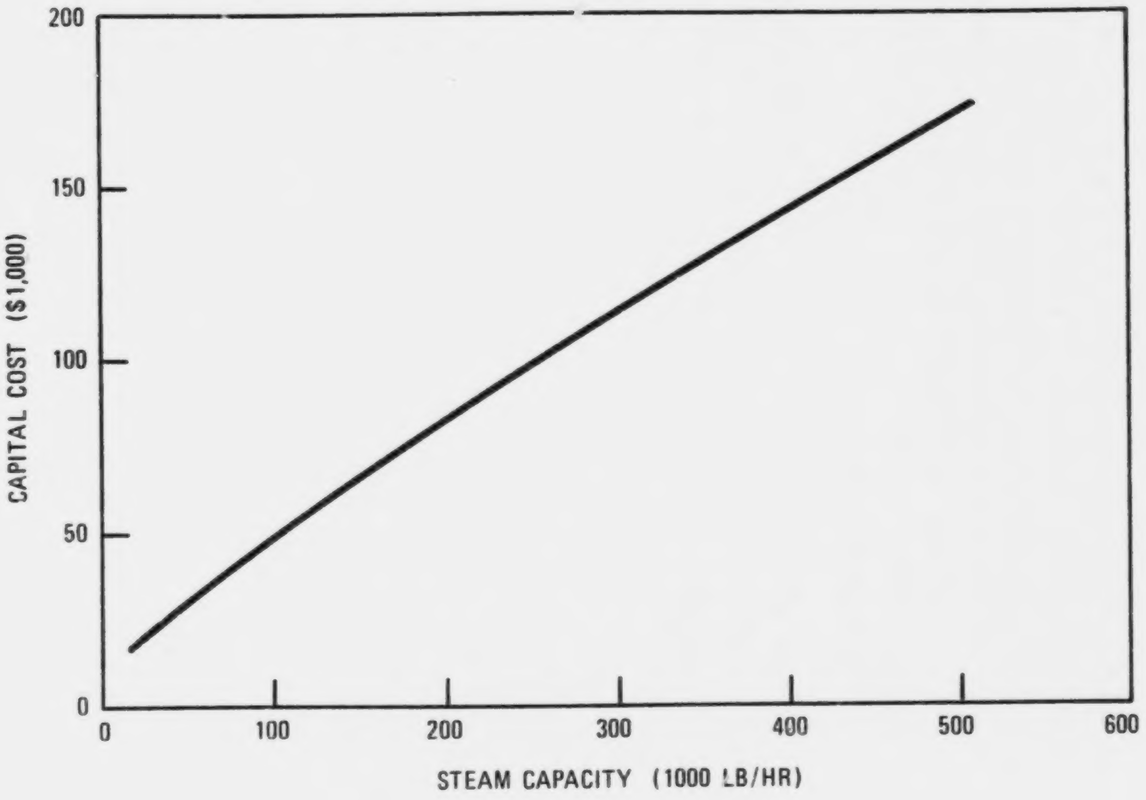


Figure 5-1. Capital Cost for Fuel Oil Storage and Handling.

For gas fuel, the requirements for fuel handling is greatly simplified, since only piping is involved (of a larger size than for oil).

c. Consideration for Low-Sulfur Residual Oil Problems

It has been noted that special problems may arise using low-sulfur residual oil [5-6]. However, this does not apply to all low-sulfur residuals, but only those with special characteristics that are derived from certain crudes, e.g., those from Libya. Special precautions must then be taken with respect to minimum temperatures for storage and pumping, etc. However, domestic fuels do not have this problem, nor those from many other foreign crudes.

It was further felt that many of the problems have been overcome by proper handling and operations and that capital or operating costs have not been a significant extra burden even with the difficult "resids." Therefore, no cost allowances were made for any fuel in this category.

d. Total Installation Cost

Total capital cost for conversion to oil and gas or to gas only is, as indicated above, the sum of the cost given in Sections 3.a. and 3.b., or Table 5-2 and Figure 5-1. For the average capacity boiler installation in each size category, these totals are shown in Table 5-3.

e. Comments on Cost Data

The only factors that were weighed in developing costs for equipment at the furnace were type of coal firing and size of unit. As a result, the costs indicated, although based on actual cases, must be considered as reflecting typical or hypothetical installations. The actual range of possibilities is very large and will include other characteristics of boiler plants that may have substantial influence on costs. This includes such factors as:

TABLE 5-3

TOTAL CAPITAL COST OF CONVERTING COAL-FIRED BOILERS

Year - 1975

Size	Average Capacity	Type of Burner	Cost of Conversion to Gas	Cost of Conversion to Oil/Gas	Cost of New Boiler Gas	Cost of New Boiler Oil/Gas
WT1	37,000	Stoker	$ 25,000	$ 35,000	$221,000	$255,000
WT2	163,900	Stoker	107,000	170,000	652,000	725,000
WT2	163,900	Pulverized	50,000	120,000	652,000	725,000
WT3	274,900	Stoker	152,000	260,000	830,000	940,000
WT3	274,900	Pulverized	65,000	165,000	830,000	940,000
FT	4,600	Stoker	8,000	20,000	17,500	27,500
CI	625	Stoker	1,000	4,000	3,000	5,000

i. age and condition of furnace and auxiliaries
ii. available space for new equipment and piping
iii. extent of instrumentation and controls
iv. extent of non-charged labor performed by company maintenance crew

For fuel handling equipment costs, the same caution is valid in consideration of the information in Figure 5-1, i.e., except for the first item, the above list of factors would all be relevant.

C. FLUE GAS TREATMENT

1. Particulate Control

a. Equipment Types

There are four types or categories of particulate control equipment in general use today -- not only for emissions from boiler stacks but from the entire spectrum of process industries as well. Variations exist according to the manufacturer or designer or specific application but there are distinguishing characteristics that make identification a simple matter despite size, age or make. Figure 5-2 shows typical examples of each type.

(1) Dry Cyclone

1. Employs centrifugal forces to separate by differential density.

2. May consist of single unit, or multiples in parallel or series.

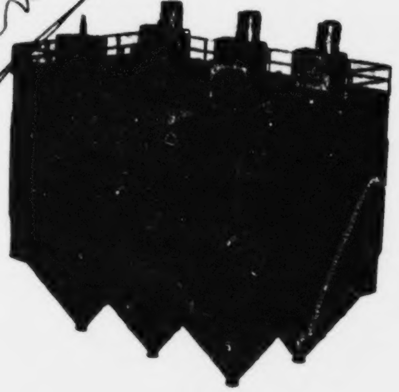
3. Except on the largest particulates, not capable of the highest efficiencies.

(2) Wet Scrubber

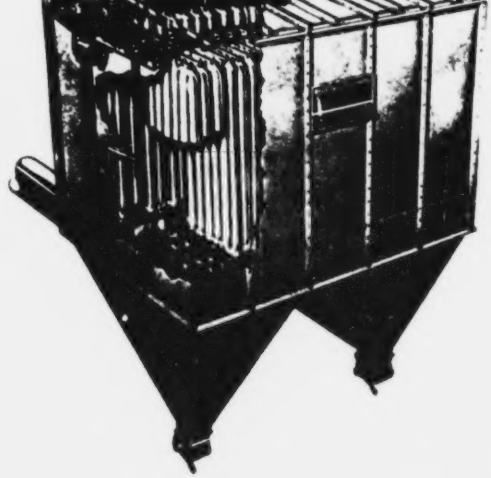
1. Depends on intimate mixing of scrubbing liquid to impinge on and entrap particulates carried by gas stream.

already run

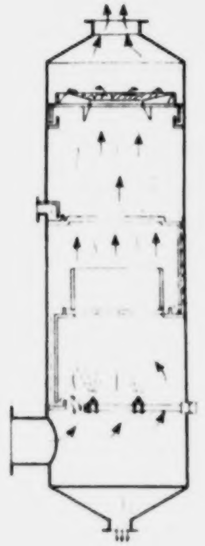
MULTIPLE CYCLONE (Western Precipitation, Los Angeles, California)



ELECTROSTATIC PRECIPITATOR (Western Precipitation)



FABRIC FILTER (Pangborn Division, The Carborundum Company, Hagerstown, Maryland)



WET SCRUBBER

Figure 5-2. Types of Collection Equipment

2a. Low to medium pressure drop characteristic of very many designs involving liquid sprays, fixed or movable packing in towers.

2b. Medium to high pressure drop characteristic of a number of venturi designs which, except for fabrication details, are very similar.

3. Can be designed for very high efficiencies.

4. Likely to have the greatest maintenance expense due to erosion and corrosion.

(3) Electrostatic Precipitator

1. Generates an electric field to charge the particulates which are then attracted to elements of opposite polarity in the precipitator.

2. Capable of the highest efficiency.

3. Will generally have the lowest pressure drop of any design; may be limited in some cases by certain flue gases which do not have favorable ionization characteristics.

4. Usually the highest cost method.

5. Efficiency can be affected by gas characteristics, e.g., adversely by low SO_2 concentration.

(4) Fabric Filter

1. Generally consists of multiple parallel cloth enclosures as bags or tubes through which the gas passes, leaving the particulates trapped on the cloth medium.

2. As with the electrostatic, capable of the highest efficiency.

3. Greatest limitation of application is design and selection of proper filter medium for adequate life span.

There are many references in the literature that describe particulate collection devices in varying depths. It was not within the scope of this study to examine the many parameters affecting selection or operation of equipment; without sacrifice of any goal, simplifying assumptions have been made in selecting representative equipment from each of the above categories and describing each in terms of significant, typical parameters which permit development of the necessary cost-effectiveness measurements.

b. Cost Analysis

A thorough review of the pertinent literature has been made, supplemented by discussions in detail with manufacturers. From this effort compromise selections typically categorizing the field of particulate collectors were developed.

The capital cost of a specific type of collector of given size depends on the manufacturer, location, and type of process for which it is designed. Examination of data from manufacturers and in the literature showed that reasonable general cost curves could be used to represent typical installations. The curves derived from that analysis are shown in Figure 5-3, and have been used in this study.

The basic form of equation for annual operating cost set forth in NAPCA Publication No. AP-51 [5-7] has been adapted for use in this program. For the four general types of control equipment, these equations have been put in the following form:

Dry Cyclone (or DC)

$$G = S[(A \times C) + (117.0 \times 10^{-6}) \frac{PHK}{E} + (M \times C)]$$

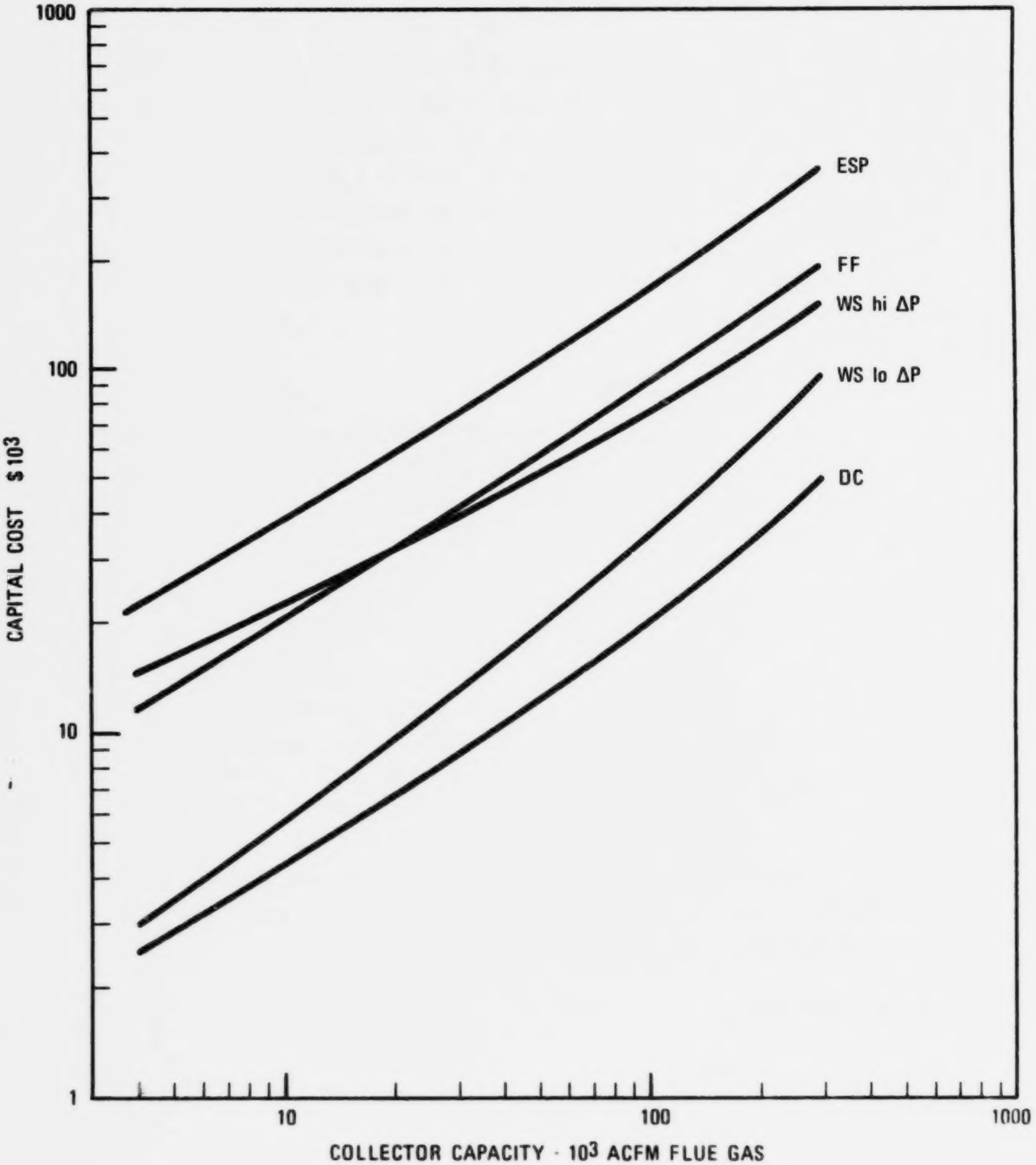


Figure 5-3. Capital Cost - Particulate Collection System.

Wet Scrubber (or WS)

$$G = S[(A \times C) + (117.0 \times 10^{-6}) \frac{PHK}{E} + (188.0 \times 10^{-6}) \frac{HKQh}{F} + WHL + (M \times C)]$$

Electrostatic Precipitator (or ESP)

$$G = S[(A \times C) + (117.0 \times 10^{-6}) \frac{PHK}{E} + JHK + (M \times C)]$$

Fabric Filter (or FF)

$$G = S[(a \times C) + (117.0 \times 10^{-6}) \frac{PHK}{E} + (M \times C)]$$

where G = dollars per year.

Actually, for these purposes, the wet scrubber type can and should be broken down into two groups as characterized by the flue gas pressure drop; there are a great variety of makes and configurations which have a generally low range of pressure drop, and there is also the venturi design with a range of pressure drop that is considerably higher.

In the above equations are many factors which have been assumed as constants. These are compromise figures, taken to simplify the calculations and results and are based on extensive study of data in the literature, from equipment manufacturers and experienced engineers.* They are intended to represent modern practice as required to effect the efficiencies herein assumed for each type of unit.

P = flue gas pressure drop	DC	4.3 in. W.C.
	WS (hi ΔP)	20 in. W.C.
	WS (lo ΔP)	6 in. W.C.
	ESP	1 in. W.C.
	FF	5 in. W.C.
Q = liquor circulation rate		0.50 gal/hr-acfm
h = total liquor head requirement		70 ft H_2O
W = make-up liquor requirement		0.05 gal/hr-acfm
J = power requirements		0.26×10^{-3} kw/acfm

---

*See bibliography at end of section.

For the variables in the equations, Tables 5-4 through 5-9 have been constructed. The appropriate units are as follows:

S = design capacity of collector, acfm of flue gas*
H - annual operating time, hours
L = liquor cost, dollars/gal (see Table 5-5)
E = fan efficiency (see Table 5-6)
F = pump efficiency (see Table 5-7)
A = annual capital cost factor, per year (see Table 5-8)
M = annual maintenance factor, per year (see Table 5-8)
K = power cost, dollars/kwhr (see Table 5-9)
C = capital cost, dollars/acfm (see Figure 5-3)

Again, compromises have been made, but the tables give some range of the respective values according to whether the variable is considered to be sensitive to size, collector type or region.

The flue gas capacities of the collectors were obtained from the respective boiler steam capacities by applying commonly acceptable conversion factors which account for differences in boiler practices resulting from fuel employed (which affects excess air) and stack temperature (which is a function of heat recovery equipment or, in practice, of boiler size and load factor) [5-8]. These factors have been reduced to a simple conversion based on uniform operation and design of equipment according to fuel and size, and are set forth in Table 5-4.

The four cost equations plus the specific values given in the various tables of this section have been incorporated as a subroutine in the STRAT program to facilitate the evaluation of particulate flue gas

---

*In all cases acfm (actual cubic feet per minute) is the basis rather than scfm (standard cubic feet per minute); this is the flue gas volume "seen" by the collector and is commonly used in gas handling calculations. The relationship is expressed thus:

$$\text{acfm} = \text{scfm} \times \frac{\text{standard pressure (or 14.7 psia)}}{\text{operating pressure (in psia)}} \times \frac{\text{operating temperature (or 460+°F)}}{\text{standard temperature (or 530°R)}}$$

TABLE 5-4

CONVERSION FACTOR FOR STEAM FLOW TO FLUE GAS FLOW AND EXCESS AIR

	Coal			
Size	Pulverized	Stoker	Oil	Gas
Excess air	20-25*	See below	12-15*	8-10*
Watertube size 1 Firetube Cast iron	0.46	0.6[1]	0.55	0.535
Watertube size 2	0.46	0.46[2]	0.41	0.41
Watertube size 3	0.46	--	0.41	0.425

$$\frac{\text{lb steam}}{\text{hr}} \times (\text{FACTOR}) = S \text{ (or ACFM)}$$

---

*Use for all sizes

[1] Underfired or overfired stokers - 50-60%

[2] Spreader stoker - 35-40%

TABLE 5-5

L - LIQUOR (WATER) COST

	Size of Unit (lb steam/hr)		
	0 ≤ 100,000	100,001-250,000	> 250,000
Cost [10^{-3} (dollars/gal)]	0.20	0.15	0.10

TABLE 5-6

E - FAN EFFICIENCY (INCLUDING MOTOR)

	Size of Unit (lb steam/hr)		
	0 ≤ 100,000	100,001-250,000	>250,000
Efficiency	0.60	0.64	0.68

TABLE 5-7

F - PUMP EFFICIENCY (INCLUDING MOTOR)

	Size of Unit (lb steam/hr)		
	0 ≤ 100,000	100,001-250,000	>250,000
Efficiency	0.51	0.54	0.57

TABLE 5-8

FACTORS FOR ANNUAL CAPITAL COST AND MAINTENANCE

Equipment Type	A	M
Dry Cyclone	0.14	0.05
Wet Scrubber		
lo ΔP	0.16	0.06
hi ΔP	0.16	0.07
Electrostatic Precipitator	0.13	0.02
Fabric Filter	0.14	0.04

A and M have the dimension of $(\text{year})^{-1}$

TABLE 5-9

ELECTRIC POWER COSTS

(K = dollars/kwh)

	Size of Unit (lb steam/hr)		
Region	$0 \leq 100{,}000$	100,001-250,000	>250,000
AT	0.029	0.021	0.016
CU	0.026	0.018	0.012
SE	0.022	0.014	0.010
WS	0.022	0.015	0.011
RN	0.028	0.016	0.011
GL	0.026	0.018	0.013

TABLE 5-10

ASSUMED COLLECTOR EFFICIENCIES FOR COAL-FIRED UNITS - % (by weight)

Dry Cyclone	94
Wet Scrubber (hi ΔP)	98
(lo ΔP)	94
Electrostatic Precipitator	99.5
Fabric Filter	99.5

treatment strategies. Unlike the case for capital cost, no plots of operating cost were prepared because the values depend on many parameters as indicated. It is necessary to use the formulas for each specific case.

The capital costs are converted to an annual basis by assuming an equipment life ranging from 15 years for wet scrubbers to 25 years for electrostatic precipitators; inclusion of the cost of money, taxes, insurance, etc., results in a total annualized capitalization factor, A, as given in Table 5-8.

c. Current Developments and Prospects

Contact with principals in APCO-sponsored contract research indicates that particulate collection requirements are adequately met with the range of equipment presently available. In comparison to the problems encountered in process industries, particulates from fossil-fuel combustion fall within a relatively narrow range of particle size and weight, loading, and other characteristics. In response to requirements, systems are available with collection efficiencies approaching 100%; the equipment itself is proven, relatively unsophisticated and competitively priced because of the many manufacturers. Present development by equipment manufacturers is not of great significance with respect to performance; rather it is sales oriented and aims to improve serviceability, corrosion resistance, operating availability, etc.

(1) Dry Cyclones [5-9]

Information regarding this classification indicates the work being done is to improve overall performance of this type -- which is generally rated the lowest in efficiency. Improved designs promise improved efficiency by means of reduced re-entrainment and better distribution of gas flow. This is particularly important as large batteries of parallel cyclones are built for some of today's huge gas flows. Flow studies are also important in working at reducing errosion maintenance.

(2) Wet Scrubbers [5-10]

The field of wet scrubbers is so very diverse that considerable activity can be found here. It is doubtful, however, that, as above, very much of it will result in significant advance of the present state-of-the-art. One particular area of activity concerns packing used in gas-to-liquid packed towers. Traditional packing in a wide variety of size, shape and material did not move, in fact, was sometimes restrained from doing so. New packing material have come into commercial use which are designed to move, one advantage being that resulting impacts prevent build-up of scale and insoluble salts and reduces the tendency to plug. This self-cleaning feature has been employed in SO_2 removal from flue gases by reaction with alkaline solutions.

A powerful rule relating scrubbing efficiency for particulate removal to specific power consumption has been expounded by Semrau [5-11]. It seems to hold for the many types of wet scrubbing devices. It would appear that any real breakthrough in scrubbing devices which can skirt this rule, i.e., get more for less, will have to operate on principles not commercially exploited at present.

The unique feature of the wet scrubber, among particulate control equipment, is that it is presently possible to adapt, for simultaneous removal of sulfur oxides and, some claim, of nitrogen oxides also [5-12]. Any wet scrubber is capable of such performance, but the higher pressure drop designs will tend to perform at higher efficiencies.

Suitability of wet scrubbing for flue gas treatment must be considered as being directly related to size. Two fluid phases, the flue gas and the scrubbing liquid, must be handled and therefore mechanical complexity, maintenance and operation are virtually doubled. It will require great ingenuity to develop a packaged scrubber of highest dependability to find acceptance in most of the intermediate size boiler range.

(3) Electrostatic Precipitators [5-13]

It can probably be generalized that all precipitators being sold today are rated at 99% or better collection efficiency. With that as a basis, it can be seen that there is little room for improvement in the performance of this equipment. Much of today's current developments have the goal of equipment that could be operated and maintained closer to their rated efficiency, whereas in actual fact, many precipitators currently operate at something less than design efficiency because of adverse flue gas characteristics, or mechanical/electrical maintenance problems. Thus, it is more realistic to employ an average, or annual, operating efficiency lower than that specified by the engineer or guaranteed by the manufacturer; this may be 0.5% or more for new installations to as much as 5% on older equipment.

One of the interesting current developments is in the field of pulse energization. This work is being sponsored by NAPCA, is presently in laboratory development with pilot scale equipment shortly to go into a test and then a field program, ultimately to be powered by full-scale commercial installation. The field trials will likely be at a TVA power plant. The theoretical background was developed some 20 years ago; however, practical application has become more likely in recent years due to improvements in electrical and electronic components. The general direction of this work is the optimization of the wave shape which will promote maximum collection efficiency of particulates; this is being done by manipulation of frequency, duration and amplitude of the electrical pulse. These pulse characteristics can be made variable and thus tailored in the individual installation to suit the particular conditions of each gas stream.

In addition to a general direction toward higher efficiencies, a large impetus for more effective precipitator performance is the use of more fuels with low sulfur content. This trend is occurring because of code requirements and because of new, large units being built in the western part of the country utilizing the vast local sources of low sulfur lignite and sub-bituminous coal. The resulting flue gases have negligible SO_3 content, with poor ionization characteristics, and correspondingly low collection results in electrostatic precipitators. This problem is being attacked by precipitator improvements and sizing and also, in some instances, by injection of SO_3 into the gas stream.

A second general area of development being followed in this field of electrostatic precipitators is on-line instrumentation that will give real-time continuous read-out of the precipitator performance. Obviously, the next step, which should not be difficult, would be to feed back this signal to minimize stack particulates by optimizing combustion conditions, or precipitator variables as described above, or both.

Because of the "acid-smut" emissions problem from residual oil-fired boilers, precipitators have been suggested; however. there have been many difficulties attending such operation. Some electrostatic precipitators are operating on oil-fired equipment in the utility industry, specifically where the furnace has been converted from coal to oil firing. Examples of this have been discussed in the literature, specifically the United Illuminating Company at New Haven, Connecticut. and the Ravenswood plant of Consolidated Edison in New York City [5-14, 5-15]. This type of operation has required considerable investment in ingenuity and alteration to obtain satisfactory efficiency and minimize the hazards of fires in the precipitator. It is not certain how much commitment to this problem is being made by the precipitator manufacturers.

The high capital cost of small units and the complexity of maintenance are factors that may continue to rule against widespread employment of electrostatic precipitators in the smaller range, at least, of intermediate-size boilers.

(4) Fabric Filters [5-16]

With respect to commercially practicable efficiencies, the bag or fabric filter is one of the most effective types of equipment in removing particulates from a flue gas. Conventionally, the particulates are those generated by the combustion process itself; however, there are several processes under development or consideration for reduction of SO_x which themselves generate substantial quantities of alkaline sulfate dust.

The results of a NAPCA study underway on filters indicates that there are three drawbacks to fabric filters which stand in the way of their more widespread employment: life of the filter media; fabrication materials of both the media and the housing to withstand corrosive attack; and pressure drop across the equipment (which is likely to be equal to or greater than any selection except high-pressure-drop wet scrubbers). Some development is underway at present by the equipment manufacturers, textile companies and developers of new fibers and it is likely that for many applications, the first two of the above three drawbacks will be substantially overcome. The third is an intrinsic characteristic and is the unavoidable cost which must be paid for its high efficiency.

There are two reasons for the attractiveness of fabric filters which indicate a growing market for improved installations: this equipment can yield a clean flue gas from low sulfur fuel that will become more common, wherein the electrostatic precipitator will be inherently less efficient due to changed flue gas ionization characteristics; secondly, a high temperature unit, able to operate in front of the air preheater equipment, would be of great assistance to plant maintenance and efficiency.

The intermediate-size boiler field may turn more to the fabric filter especially if urban codes for particulates become very stringent. It is quite conceivable that well-designed, fully-automated filter installations could be designed for this market. Its chief drawback, as given above, would be a high pressure drop reflected in large fans and fan power; compared to cyclones, scrubbers and precipitators, however, it may be both more efficient and simpler to operate.

2. Sulfur Dioxide Removal

a. Process Description

(1) General

A preliminary review of air pollution abatement processes which would remove SO_2 and NO_x individually or simultaneously from the boiler flue gases reveals that there are presently no processes demonstrated for NO_x removal and that few SO_2 recovering processes appear applicable to small boilers. However, all non-regenerative and throwaway processes appear to be applicable.

Due to high equipment cost and operational complexities, the recovery of the sulfur and the regeneration of the sorbents appear feasible only on a regional centralized basis for small boilers. Ideally the throwaway processes and the regionalized recovery processes would require the same design of equipment for each boiler, with the only difference between the concepts being that the chemicals would be transported to a disposal area and a recovery plant, respectively. Sulfur recovering processes not amenable to centralized regeneration recovery (such as the Monsanto Cat-ox scheme) were excluded as being impractical for intermediate boilers.

About two dozen SO_2 removal processes at various stages of development are now under investigation [5-17]. Some of these processes are at the bench scale level of development, others at the pilot plant stage, and two have been built as semi-commercial units with flue gas rates equivalent to those of 15 and 150 Mw power plants. Most of the removal systems are the regenerative type, in which a sulfur by-product is recovered and the reactive chemicals are recycled. A few of the systems are the non-regenerative or throwaway type, where the reacted sulfur and additive are discarded.

The throwaway processes use natural minerals such as nahcolite, limestone and dolomite as chemicals to react with the sulfur oxides in the flue gas. Limestone and dolomite were chosen as absorbents because they are readily available in wide areas of the country at relatively low cost, say $2 to $3.50 per ton at the quarry. Nahcolite is more reactive in its natural state than limestone or dolomite, but has not yet been mined commercially and its market price is, therefore, unknown.

There is no process that is applicable to all boiler units. Location and fuel are considerations which make one process more applicable than others. For example, at locations in a rural district where land is available at low cost, the throwaway processes may be more practical because the spent chemicals can be discarded at the site at a relatively low cost. In industrialized urban areas where there may be a demand for sulfur products and where land costs are high, recovery processes should be more practical.

Detailed economic evaluations are not available for most of the processes. The few which have been published are incomplete and are based on different assumptions. Some of the economic evaluations and process designs are based only on laboratory bench studies and are scaled up directly to approximately 1,000 Mw power plants, a procedure which generally leads to an unrealistic process design and economic evaluations of questionable accuracy.

Nearly all of the SO_2 recovery processes under investigation by commercial interests are being developed for application to large generating stations or to a very large single boiler. Because of the scale, capital and operating costs are minimized, relatively speaking, thus maximizing potential return from the recovered by-product. However, this approach does not offer a solution for industrial, commercial and small utility boilers.

Due to recent and continuing depressed prices for sulfur, the SO_2 recovery processes are presently at an economic disadvantage; the rates of return on invested capital are either non-existent or very low, even for a large utility installation. Therefore, complete installation of one of the present sulfur recovery processes on a small boiler will not even approach economic feasibility.

There is a possibility of economic recovery of the sulfur if the industrial and utility boilers in a district could share a common sulfur recovery plant. The sulfur would be removed from the flue gases by a sorbent, transported to the recovery plant where it would be separated from the sorbent and manufactured into saleable by-products; the sorbent would be recycled to the boiler.

The centralized recovery plant concept is not an innovation, since one company has proposed demonstration plants for such a system for large utility plants [5-18]. However, full commercialization of the concept demands a high concentration of participating boilers -- utility, industrial and commercial -- in a given area so that a large recovery unit can be constructed to maximize economy of scale while keeping the transportation burden to the participating plants at a minimum. In regions where the concentration of boilers is too low to use the centralized recovery concept, throwaway processes are the alternative for removal of the SO_2 from the flue gases of intermediate boilers.

(2) Throwaway Processes

The throwaway processes remove the SO_2 either in an aqueous or gaseous state. The dry systems tend to pose fewer disposal problems; the wet systems are more efficient. There is little operating data available on these systems. Although there do not appear to be any fundamental limitations in application to intermediate-size boilers, a number of problems are expected to be encountered. Plugging and scaling are general problems in alkaline scrubbers. Instrumentation and process controls for unattended (or at best employment of relatively untrained operators in the technology of chemical processes) installations have not been developed. Space limitations in existing installations may be severe. There are certain to be other problems.

(a) Nahcolite Dry Process ($NaHCO_3$)

The nahcolite process is being promoted by the Precipitair Pollution Control Company. This process uses the mineral nahcolite (natural sodium bicarbonate) to remove the SO_2 from the flue gas. Powdered nahcolite is injected into the flue gas whereupon the reaction to sulfate occurs and the product is removed from the flue gas in a dry dust collector. The highest SO_2 removal obtained to date has been 70 percent while using a bag collector and 100 percent stoichiometric additive feed rate. Lower removal rates are expected with other types of dry collectors, such as electrostatic precipitators and cyclones, since the contact and reaction between SO_2 and the additive is maximized by intimate contact on the filter surface itself. This process warrants additional consideration if there are indications that nahcolite will become available at a reasonable cost.

This process is one of the most practical processes which can be applied to small boilers. The process equipment is simple, but capital cost is high due to the high cost of the bag filter. The total annual operating cost is also high, since the additive chemical cost was assumed to be $35 per ton, delivered.

However, the process offers several attractive advantages by producing a dry but soluble inert, inorganic waste product, Na_2SO_4. The waste can be readily transported for disposal or recovery or possibly disposed through the local sewage system, if an accomodation can be reached with local water pollution officials.

(c) Na_2CO_3 Wet Process (Scheme B)

The wet sodium carbonate process utilizes a solution of sodium carbonate to absorb the SO_2. The additive Na_2CO_3 is dissolved in water before it is sprayed into a wet scrubber for reaction with the SO_2. The product from the scrubber is a solution of Na_2SO_3, $NaHSO_3$ and Na_2SO_4 which could be regenerated if desired or discarded to the sewage system. A process is now being developed by the Chemico Co. that is capable of regenerating the waste solution.

The advantage of the soda ash scrubbing system is that it is simple and easy to operate. The waste disposal is not expected to be a major operating cost since the inert effluent would not be harmful to local sewage systems or receiving boilers of water.

(d) TVA Dry Limestone Process (Scheme C)

Another potential throwaway removal process is the TVA dry limestone system [5-19]. Finely pulverized limestone is injected into a high temperature region of the furnace for calcination and reaction with the SO_2. The additive containing reacted sulfur is swept through the furnace and is removed in some particulate collector, perhaps an electrostatic precipitator or bag filter prior to entering the stack.

The gas phase reaction between lime and SO_2 proceeds more slowly than in a water solution and only part of the SO_2 is removed. However, by using two to three times the stoichiometric amount of limestone, from 30 to 50 percent SO_2 removal is claimed.

The applicability of the dry TVA process depends on the limestone cost, disposal cost and air quality regulations. At present, the TVA process is not applicable in regions where fuel containing 1 percent sulfur, or equivalent SO_2 removal air quality is enforced. When burning 3 percent sulfur fuel, an SO_2 removal of 67 percent would be required to meet the code, which is higher than has been achieved to date with the TVA system.

The disadvantage of the TVA dry lime system is that great quantities of waste are produced due to the low chemical efficiency. The disposal of a substantially insoluble dry waste could be a significant operating cost, especially on small boilers. The additive feeding and waste handling equipment are also expensive because of the large quantities required to remove a significant amount of SO_2. Nevertheless, the dry TVA process has the lowest net annual operating cost for the pulverized coal-fired boilers, because the combined spent additive and ash are handled and discarded in a dry state, and it is not necessary to pay for the transportation of water as in the wet system.

(e) Combustion Engineering Dolomite Process (Limestone), (Scheme D)

The process promoted by Combustion Engineering, Inc. is one of the only two systems which have been tested on a prototype installation [5-20,5-21,5-22]. The operation of the prototype on a 150 Mw unit has not been entirely satisfactory to date; mechanical failures and calcium scaling have caused unscheduled shutdowns of the test unit.

In this process, the SO_2 is absorbed in a lime slurry in a wet scrubber. The lime is obtained by the injection of finely pulverized dolomitic limestone into the boiler where it is calcined according to the reaction $CaCO_3 \rightarrow CaO + CO_2$. Calcination is necessary to make the limestone more reactive with the SO_2.

The lime reacts with all SO_3 present and a portion of the SO_2 during its passage through the furnace and gas ducts, but a wet scrubber is necessary to provide additional contact resulting in higher percent removal of the SO_2, plus adequate particulate collection. In the wet scrubber the SO_2 reacts to form calcium sulfate and sulfite precipitate. The precipitate and fly ash are separated from the scrubbing liquor by a settling tank or pond. The supernatant is recycled to the scrubber and sludge is wasted to sludge holding beds. The water overflow from the sludge pond containing dissolved calcium and magnesium salts may have to be treated to reduce oxygen demand, dissolved solids and suspended solids before discharge to receiving waters.

Primarily, the C-E process applicability depends on the cost of the limestone, disposal cost and boiler design of existing units. Water supply, receiving water characteristics, sulfur content in the fuel, ambient air characteristics, unit size, load factor and type of fuel are other factors that should be evaluated in the consideration.

The C-E process appears applicable to small utility and large industrial boilers because the limestone is often available at relatively low cost. However, the process has not demonstrated its ability to operate for an extended period of time. Calcium scaling and fouling of equipment could severely reduce the boiler on-stream availability and increase maintenance cost.

(f) $CaCO_3$ Scrubbing (Scheme E)

An alternative to the above is to keep the sorbent out of the furnace and employ it in the scrubber only. This appeals especially to the boiler operator who generally is not anxious to put anything other than fuel and air into the furnace.

In particular, most oil fired boilers are not designed for handling dust-laden combustion gas and the injection of limestone is bound to cause some degree of fouling of heat transfer surfaces and plugging of gas passage. This in turn would make desirable installation of additional soot blowers.

The difference in these two schemes, from the standpoint of SO_2 removed is that the scrubbing here is done with $CaCO_3$ in solution rather than the product of calcination, CaO, in solution. As a result of using this less reactive scrubbing agent, an efficiency of no more than 60% has been selected.

(g) CaO Scrubbing (Scheme F)

This scheme, as with B and E, keeps the sorbent out of the furnace, adding it at the scrubber instead. It is a compromise between these two, however; by employing CaO (i.e., calcined limestone) it falls between the others in reactivity, efficiency of SO_2 removal and also in cost of make-up chemical. Being calcium base, its waste disposal characteristics will have the same low solubility as the other limestone schemes.

(3) Application of Regional SO_2 Recovery Systems to Small Boilers

As previously mentioned, it would not be practical to install a complete sulfur recovery process on small individual boilers, but, if all boilers in a region could share a sulfur recovery process, recovery of a sulfur product could become practical. The regional recovery plant concept would eliminate duplication of recovery equipment at each installation, thus reducing the unit cost of the sulfurous by-product. Also, the equipment requirement and capital expenditures would be minimized at each boiler site.

Very possibly, the major equipment at each boiler site would be identical to the equipment necessary for the throwaway processes previously discussed. The only difference would be that the chemicals would be transported to a recovery plant instead of being transported to a storage and disposal area. The central processing plant would recover and sell a sulfur product to offset its operating and transportation costs and recycle the reactive alkaline chemical to the power plant.

Of about two dozen SO_2 removal and recovery processes examined, only four appear to be applicable to the regional recovery concept, viz. the Chemico, the Stone & Webster/Ionics, the Wellman-Lord and the Molten Carbonate processes.

The Chemico process, which was developed for regionalization, appears to be the most versatile and can be installed on either old or new and coal- or oil-fired boilers since it does not necessitate modifcations to the boiler. The Wellman-Lord process and the Stone & Webster/Ionics process are also applicable to regionalization, but either higher transportation costs or higher capital costs for concentrating equipment must be incurred.

If transportation costs of the sorbent to and from the regional recovery plant turn out to be the critical economic factor, the Molten Carbonate process may prove to be the most practical for new installations -- but not for the large number of intermediate boilers which are not operated on an essentially continual basis.

(a) Chemico Process

The Chemico process is presently being developed jointly by Chemical Construction Corporation and Basic Chemicals Company [5-18]. The process is presently the only system specifically developed for the recovery of the sulfur and chemicals at a centralized plant.

The Chemico process is a wet system which uses a slurry of magnesium oxide to absorb the SO_2, forming a precipitate of $MgSO_3/MgSO_4$. The scrubbing liquor is concentrated and crystalized for shipment to a central recovery plant. At the recovery plant the $MgSO_3/MgSO_4$ is decomposed in a kiln to produce concentrated gaseous SO_2 and powdered MgO. The MgO is then returned to the scrubbing system.

The disadvantage of the Chemico system is that the $MgSO_3/MgSO_4$ solution is relatively dilute and, to minimize shipping costs, should be concentrated and crystallized before it can be shipped to the central recovery plant, necessitating a filter, crystallizer and dryer at the boiler. However, the regenerated MgO is in a dry phase which is easily shipped back to the users. Overall, the Chemico process is one of the more practical systems that can be readily utilized in the regional centralized concept for small boilers.

(b) Stone & Webster/Ionics Process

The Stone & Webster/Ionics Process, which is being developed jointly by Stone & Webster Engineering Corporation and Ionics Company, is one of the most technologically advanced and promising SO_2 recovery processes [5-24]. The process was operated at a pilot plant in Tampa, Florida, and a prototype plant is now being designed. The pilot plant tests indicated satisfactory levels ($\geq$90%) of SO_2 removal were feasible and that further demonstration of the process was warranted.

The SW/I Process is based on sodium hydroxide absorption of the SO_2. The formed sodium sulfite-bisulfite solution is reacted with sulfuric acid (H_2SO_4), generated internally, to form sulfur dioxide and sodium sulfate solution. The sodium sulfate is processed in the electrolytic cell to general sodium hydroxide and sulfuric acid which are recycled to process. The SO_2, which is recovered as pure gas, can be used to manufacture sulfuric acid or elemental sulfur.

The disadvantage of the SW/I Process is that relatively dilute solutions have to be transported between the boiler and the recovery plant. The solutions could be concentrated and crystalized but it would mean higher capital expenditure at each boiler site and at the recovery plant.

(c) Wellman-Lord Process

The Wellman-Lord Process is also a wet scrubbing process; the absorbing solution is K_2SO_3 [5-25]. In the scrubber, $KHSO_3$ is formed which will crystalize and precipitate upon cooling.

The metabisulfate crystals ($K_2S_2O_5$) when heated with steam will give up one mole of SO_2 per mole of $K_2S_2O_5$ and forms an aqueous solution of K_2SO_3. The K_2SO_3 is recycled.

The Wellman-Lord Process has the same disadvantage as all the other aqueous regenerative processes; that is, relatively weak solutions have to be handled both to and from the recovery plant or concentrated and crystalized at the respective sites. The Wellman-Lord Process is being developed with minimum public disclosure of results and progress.

(d) The Molten Carbonate Process

The molten carbonate process being developed by the Atomics International Division of North American Rockwell is still in the bench scale development stage and design details are sparse [5-23].

However, the molten carbonate process appears to be one of the most adaptable processes to the regional recovery plant concept for new installations.

In this process the SO_2 is adsorbed in a molten salt at approximately 800°F. The molten salt solution is regenerated by reducing the sulfate to sulfide and reacting the sulfide with CO_2 to produce carbonate salt and H_2S gas. The H_2S can be used to manufacture elemental sulfur. On coal fired units, a high temperature precipitator is necessary to remove the ash before the flue gas is contacted with the molten salt. Low temperature heat recovery equipment would be installed after the SO_2 absorber to maintain normal boiler efficiency. The molten carbonate system is more applicable to new installations because it will be easier and cheaper to perform the necessary boiler modification. If this system were applied to the regional recovery plant concept, only the SO_2 absorption system would be needed at the boiler site, and the complete recovery plant would be centralized. The carbonate process is attractive, since no excess sorbent or water would be transported between the boilers and the central recovery plant.

There is a substantial drawback to this process in that the high operating temperature of the unusual adsorbent would almost completely preclude all boilers except those operating continually throughout the year. Thus, only large boilers in process industries are likely candidates for consideration.

(e) Basis of Design

1. Selection. After a review of available processes, the six listed in Table 5-11, and described in a series of flow charts (Figures 5-4 through 5-9) were selected for detailed economic costing and evaluation to develop the necessary data for cost-effectiveness measurements. Those selected have been studied and tested and appear to have the highest likelihood of satisfactory performance and design efficiency, or they are variations which are most closely related to such advanced schemes. General availability of feed chemicals at

TABLE 5-11

SO_2 REMOVAL SYSTEMS FOR INTERMEDIATE BOILERS

Designation	Description	Developer	Figure Number	Chem. Feed Rate	SO_2 Removal Efficiency
A	Dry Sodium Carbonate (Na_2CO_3) and fabric filter	(Nahcolite Alternative)	5-4	110	60
B	Sodium Carbonate (Na_2CO_3) Scrubbing	---	5-5	110	95
C	Dry Calcium Carbonate ($CaCO_3$)	TVA	5-6	200	40
D	Dry Calcium Carbonate ($CaCO_3$) and Scrubber	C.E.	5-7	110	90
E	Calcium Carbonate ($CaCO_3$) Scrubbing	---	5-8	110	60
F	Calcium Oxide (CaO) Scrubbing	---	5-9	110	90

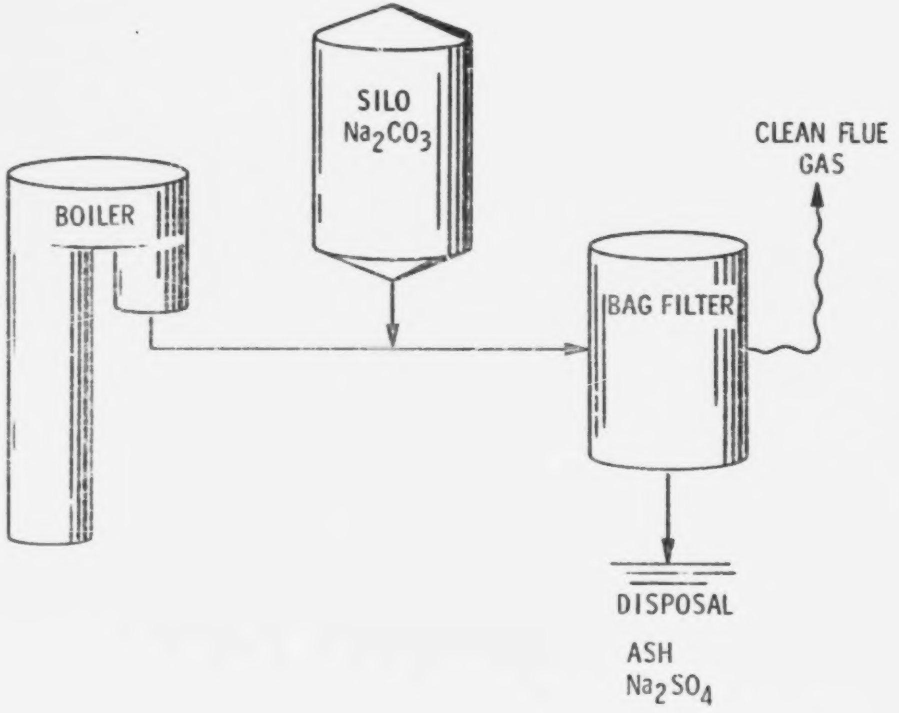

SILO
Na_2CO_3
BOILER
CLEAN FLUE GAS
BAG FILTER
DISPOSAL
ASH
Na_2SO_4

Figure 5-4. SO_2 Removal with Dry Sodium Carbonate - Bag Filter (Scheme A).

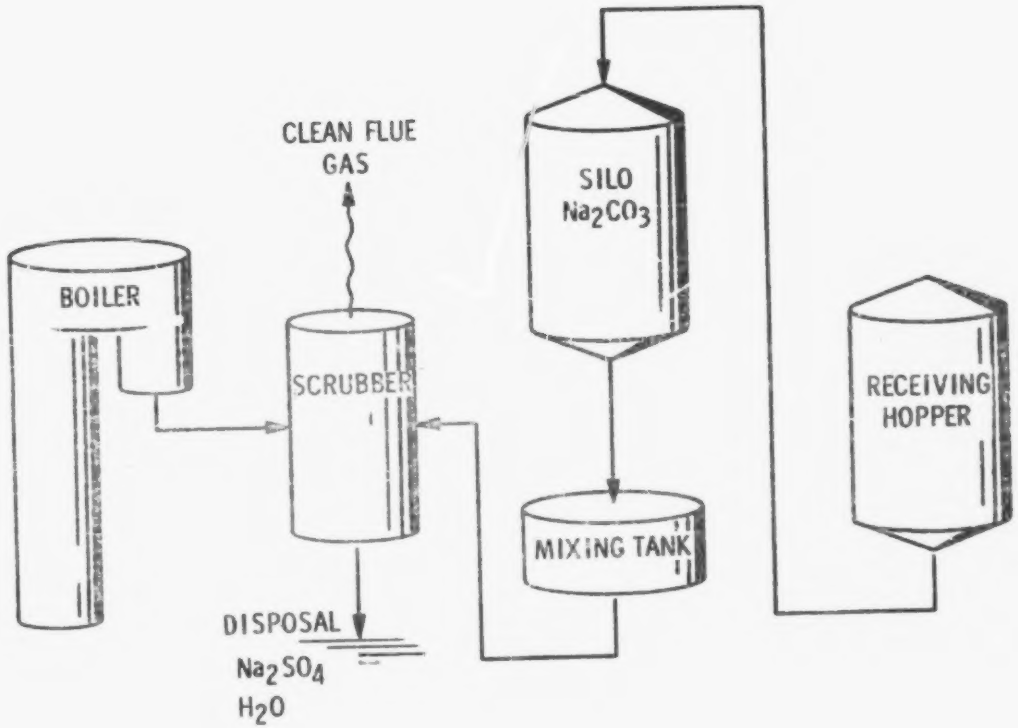

CLEAN FLUE GAS
BOILER
SCRUBBER
SILO Na_2CO_3
MIXING TANK
RECEIVING HOPPER
DISPOSAL
Na_2SO_4
H_2O

Figure 5-5. SO_2 Removal with Sodium Carbonate - Wet Scrubbing (Scheme B).

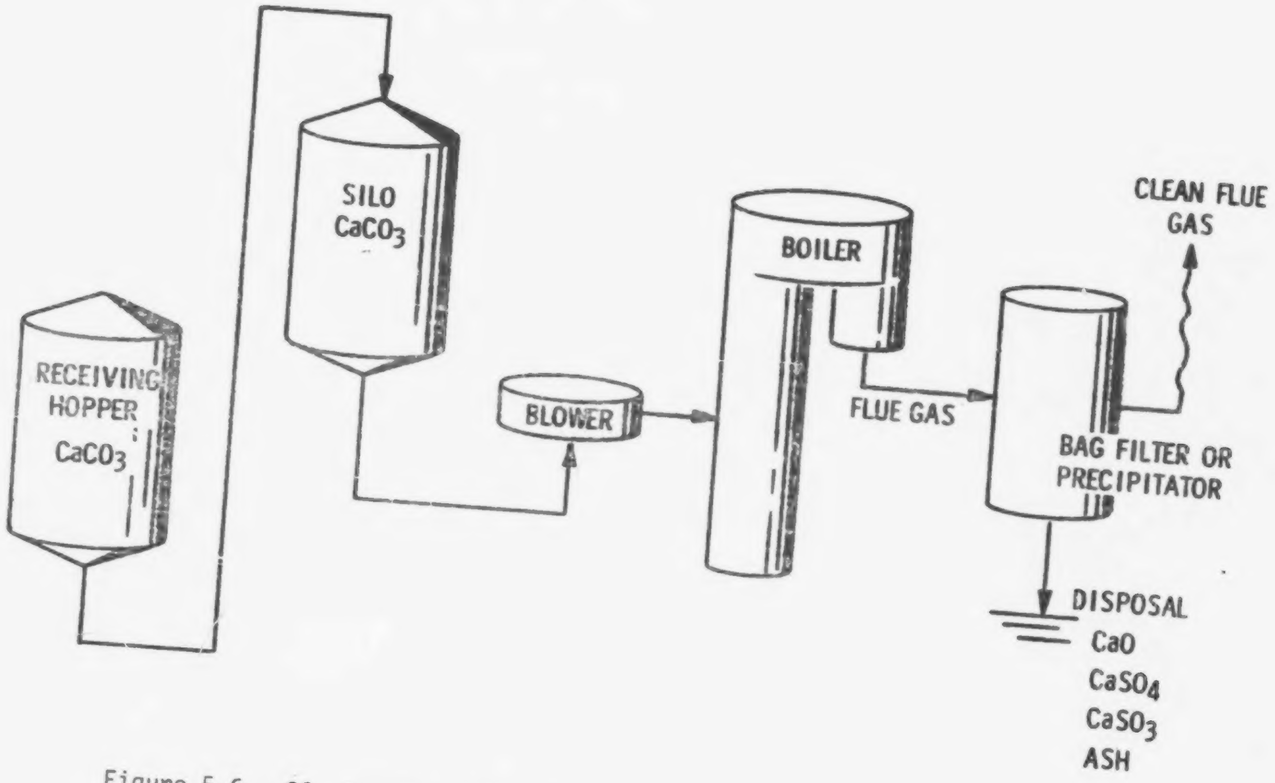

RECEIVING HOPPER $CaCO_3$
SILO $CaCO_3$
BLOWER
BOILER
FLUE GAS
BAG FILTER OR PRECIPITATOR
CLEAN FLUE GAS
DISPOSAL
CaO
$CaSO_4$
$CaSO_3$
ASH

Figure 5-6. SO_2 Removal with Dry Calcium Carbonate - Precipitators (Scheme C).

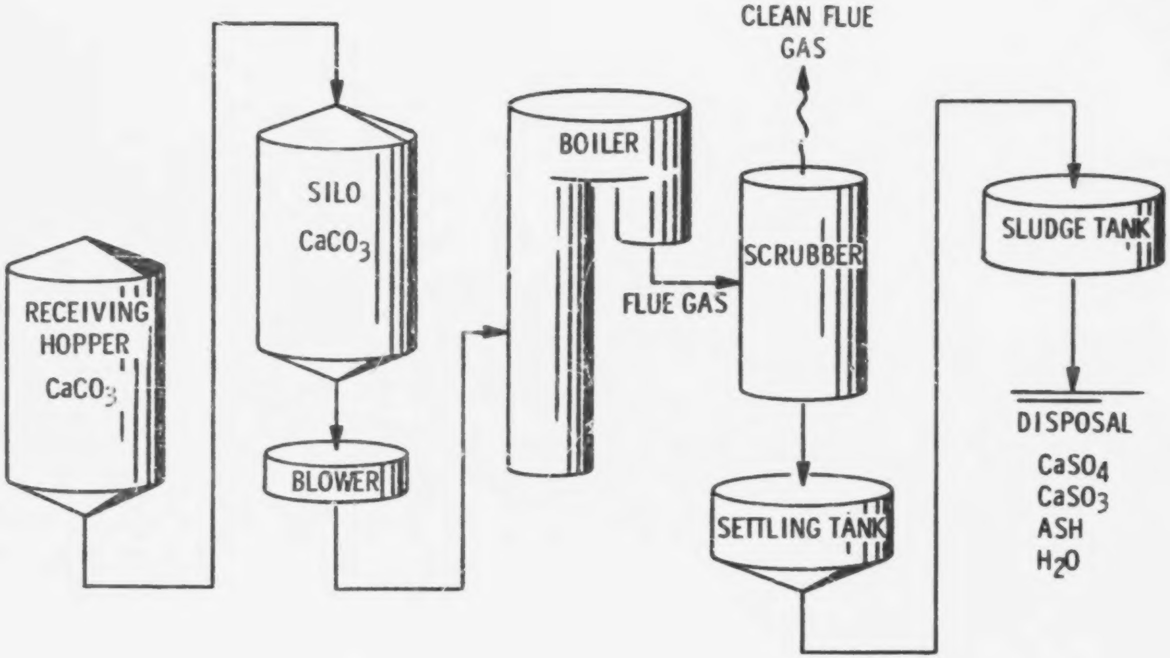

RECEIVING HOPPER
$CaCO_3$
SILO
$CaCO_3$
BLOWER
BOILER
FLUE GAS
CLEAN FLUE GAS
SCRUBBER
SETTLING TANK
SLUDGE TANK
DISPOSAL
$CaSO_4$
$CaSO_3$
ASH
H_2O

Figure 5-7. SO_2 Removal with Dry Calcium Carbonate - Scrubbing (Scheme D).

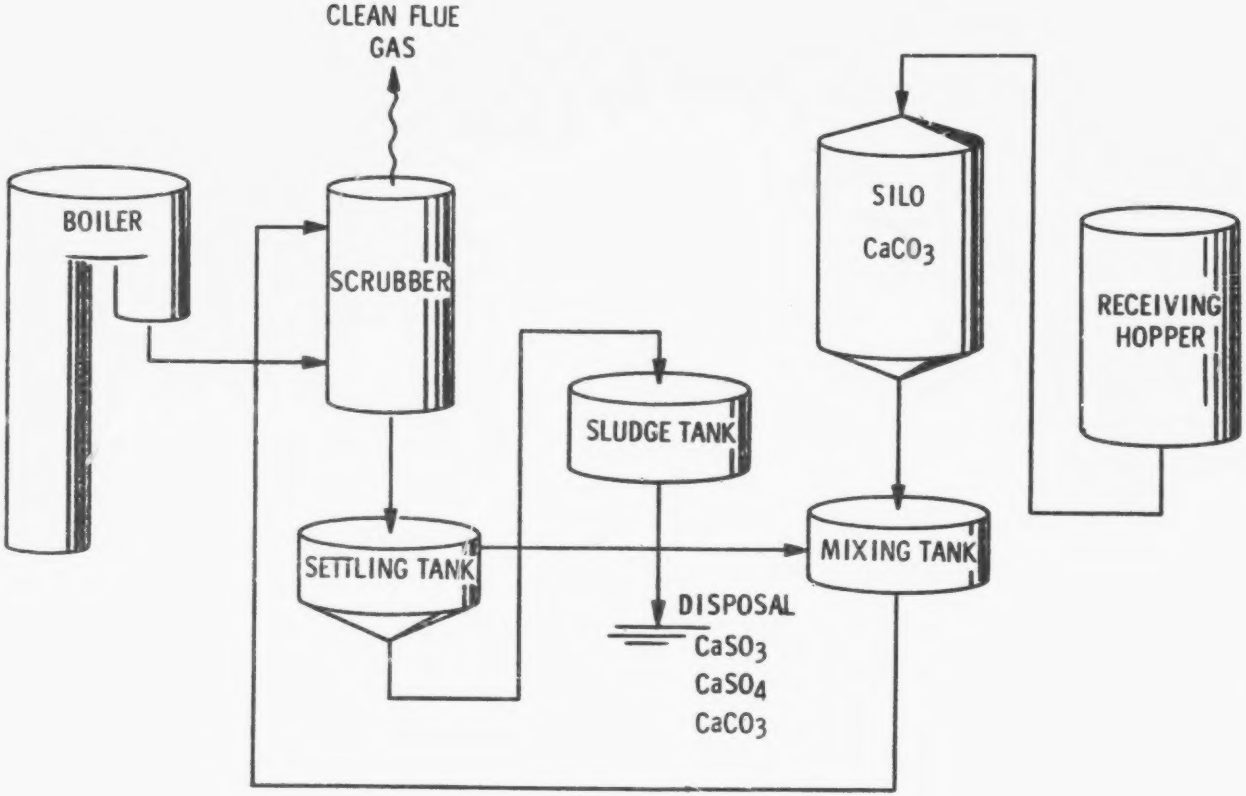

CLEAN FLUE GAS
BOILER
SCRUBBER
SLUDGE TANK
SILO
$CaCO_3$
RECEIVING HOPPER
SETTLING TANK
MIXING TANK
DISPOSAL
$CaSO_3$
$CaSO_4$
$CaCO_3$

Figure 5-8. SO_2 Removal with Wet Calcium Carbonate - Scrubbing (Scheme E).

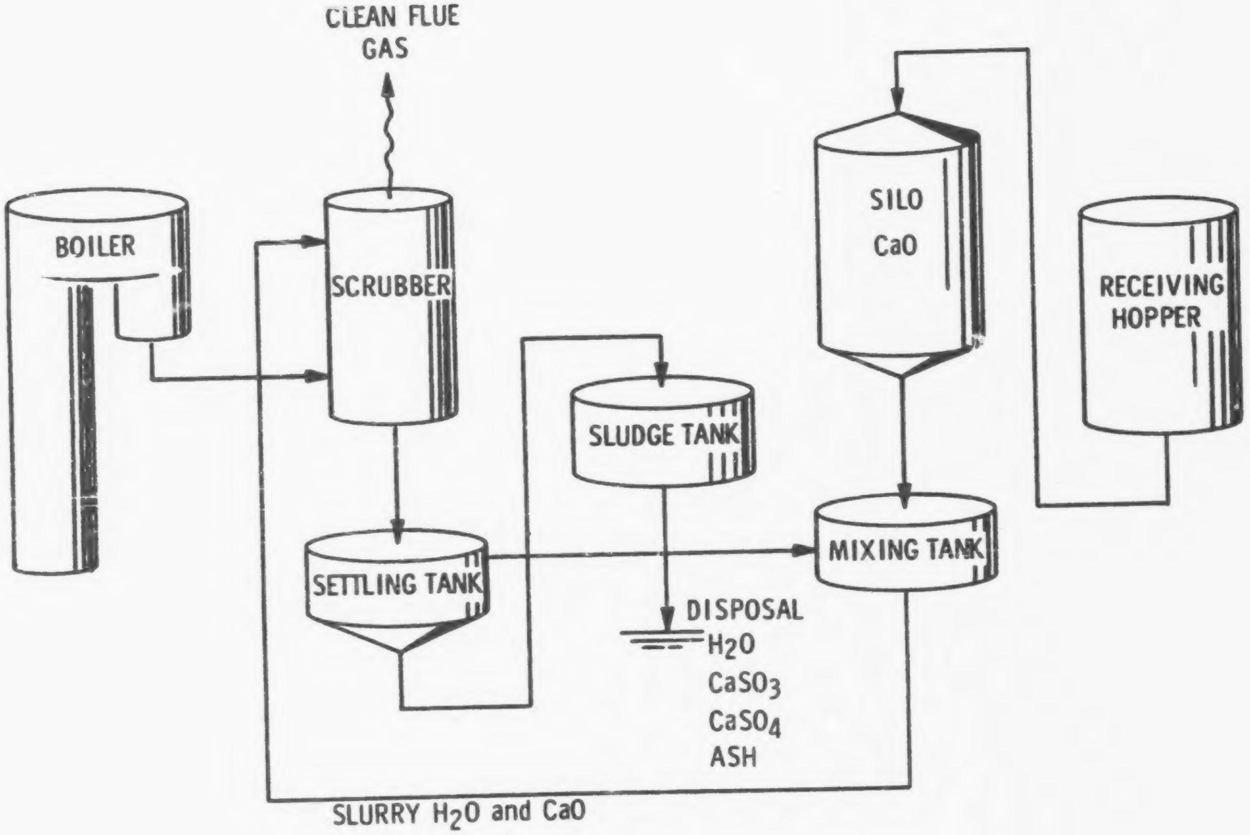

CLEAN FLUE GAS
BOILER
SCRUBBER
SETTLING TANK
SLUDGE TANK
DISPOSAL
H_2O
$CaSO_3$
$CaSO_4$
ASH
SILO
CaO
MIXING TANK
RECEIVING HOPPER
SLURRY H_2O and CaO

Figure 5-9. SO_2 Removal with Calcium Oxide - Scrubbing (Scheme F).

reasonable cost was also considered important. (The selection process resulted in elimination of all the sulfur recovery schemes, whether centralized or not, as being presently impractical for intermediate-size boilers.)

2. Process Efficiency. The rate of application of chemical feed as percent of stoichiometric requirement (of the sulfur in the fuel), and the expected or design efficiency of SO_2 removed from the stack gas is also indicated in the table.

3. Boiler Efficiency. Reasonable, commercial efficiencies have been assumed for each range of boiler sizes; this figure in turn dictates fuel consumption and is a factor in the determination of flue gas quantity.

Boiler Size	Efficiency
<100,000 lb per hour	77%
100,001-250,000 lb per hour	83%
>250,000 lb per hour	89%

4. Flue Gas Quantity. This parameter is expressed in terms of actual cubic feet per minute (acfm) or the actual volume that will pass through the control equipment at the normal operating conditions of temperature and pressure. (This has been defined in the section on Particulate Control, Table 5-4).

Assumptions, based on commercial practice, have been made in regard to certain variables which, like efficiency, determine total flue gas volume; these include excess air employed for each fuel and firing method (Table 5-4), and exit gas temperature. The following table indicates the values considered typical and used in this study.

Size Category pph	Average Unit Size-pph	Fuel	Stack Gas Volume-acfm
<100,000	30,000	Oil	17,800
		Coal	18,000
100,001-250,000	158,000	Oil	64,800
		Coal	69,000
>250,000	320,000	Oil	130,300
		Coal	148,000

5. Chemical Costs. Average, delivered costs for bulk chemicals for the wet and dry absorption processes were assumed as follows:

limestone and/or dolomite	$5/ton
calcined limestone	$15/ton
soda ash	$35/ton

Actual operating costs for chemical additives will be proportional to sulfur content of fuel.

6. Slurry Disposal. Waste slurry from wet scrubbing processes using lime additives was assumed to have a composition of 35% solids - 65% water by weight.

Disposal cost of end products from all systems was assumed at $5 per ton (wet basis).

7. Other Operating Costs. Maintenance allocation at five percent of total capital cost was used for all systems.

Operating labor was assumed as follows:

Boiler Size	Annual Labor Cost
<100,000 lb per hour	$1000
100,001-250,000 pph boiler	$5000
>250,000 pph boiler	$5000

Electric power rates were determined by examination of typical rates and power consumption data for various size industries are indicated by boiler sizes:

Boiler Size	Power Cost
<100,000 pph boiler	$0.029 per kwhr
100,001-250,000 pph boiler	$0.022 per kwhr
>250,000 pph boiler	$0.016 per kwhr

Water costs for make-up to scrubbers was included but found to be not significant.

8. Load Factor. For a given size unit, virtually all generating costs will be a function of the load factor, i.e., what portion of the time and what percent of capacity the equipment is being utilized. For the smallest boilers and their corresponding utilization, it is assumed that these are essentially heating plants and are assigned the lowest load factor; with increasing size, process and power will be increasingly significant in steam consumption and thus load factors increase (where utility boilers have a national average of about 54%, it is conceivable that a boiler in a continuous process industry may run at 100% ± at all times, excepting only a likely week or two at no-load for plant "turn around", maintenance, or vacation). The following table gives the values assumed:

<100,000 pph boiler	21% load factor
100,001-250,000 pph boiler	35% load factor
>250,000 pph boiler	55% load factor

(f) Summarized Cost Data

1. Capital Cost. Under sub-contract Stone & Webster Engineering Corporation examined the candidate emissions control processes and made estimates of capital cost for each based on their experience in power and process plants. They employed accepted engineering procedures of equipment quotations, material take-off,

construction costs, etc., including structural, electrical, piping and other crafts and equipment, plus a contingency of 20% for systems that are fundamentally new, untried and not debugged.

These estimates are shown in Table 5-12 for each process at a new installation and at an existing boiler plant. For schemes A and C, oversize particulate collection equipment was included because of the great increase over normal combustion-associated loads. For the schemes B, D, E, and F at a new boiler plant, it has been assumed that the wet scrubber installed for SO_2 control would also be adequate for particulate control. Therefore, credit has been given for omission of a particulate collector that would otherwise have been installed. A similar allowance at an existing plant would not be in order.

2. Operating Cost. Table 5-13 shows total annual operating cost for each SO_2 control scheme. This includes all operating costs such as labor, maintenance, utilities, chemicals, etc. as indicated above.

Also included was an allowance for annual capitalization expense, taken at 21% of total capital cost. This value is higher than that used for other emissions control equipment. The difference is principally due to the assumption that these systems cannot be expected to have a long life since (1) they are essentially first-generation processes which, in all likelihood, will be later replaced by newer, more economical and/or more efficient concepts, and (2) because of operating in a generally corrosive environment, their operating life will not match that of the boiler plant itself.

3. NO_x Removal and Recovery

The oxides of nitrogen (NO_x) which are emitted by fossil-fuel burning equipment are a result of the direct oxidation, at flame temperatures, of atmospheric nitrogen and of the nitrogen in the fuel. At the flame temperatures, the oxidation of nitrogen results in the formation of nitric oxide (NO). Although the NO becomes unstable as the gas temperature decreases, there is not enough residence time in the boiler and not enough

TABLE 5-12

SULFUR DIOXIDE REMOVAL FROM FOSSIL FUEL BOILER FLUE GAS
(CAPITAL COST IN $1000)*

	A		B		C		D		E		F	
	Na_2CO_3 (Dry)		Na_2CO_3 (Wet)		$CaCO_3$ (Dry)		$CaCO_3$ (Dry) & Wet Scrubber		$CaCO_3$ (Wet)		CaO (Wet)	
Size and Fuel	New	Conversion	New	Conversion	New	Conversion	New	Conversion	New	Conversion	New	Conversion
275,000 lb/hr												
Coal, Pulverized	510	730	285	480	360	520	275	471	275	471	275	471
Coal, Stoker	510	730	285	480	---	---	---	---	275	471	275	471
Oil	610	710	268	375	356	550	377	470	377	470	377	470
164,000 lb/hr												
Coal, Pulverized	355	485	188	320	263	365	187	312	187	312	187	312
Coal, Stoker	355	485	188	320	---	---	---	---	187	312	187	312
Oil	425	470	182	250	328	400	258	320	258	320	258	320
37,000 lb/hr												
Coal, Pulverized	---	---	---	---	---	---	---	---	---	---	---	---
Coal, Stoker	---	---	110	152	---	---	---	---	---	---	110	150
Oil	190	206	88	105	169	190	---	---	135	158	135	158

---

*For comparison, new boiler costs alone are approximately $900,000 for the 275,000 pph size, $700,000 for the 164,000 pph size, and $230,000 for the 37,000 pph size.

TABLE 5-13

SULFUR DIOXIDE REMOVAL FROM FOSSIL FUEL BOILER FLUE GAS

(TOTAL ANNUAL OPERATING COST IN $1000)

Assuming 3% Sulfur

	A		B		C		D		E		F	
	Na_2CO_3 (Dry)		Na_2CO_3 (Wet)		$CaCO_3$ (Dry)		$CaCO_3$ (Dry) & Wet Scrubber		$CaCO_3$ (Wet)		CaO (Wet)	
Size and Fuel	New	Conversion	New	Conversion	New	Conversion	New	Conversion	New	Conversion	New	Conversion
275,000 lb/hr [1]												
Coal, Pulverized	422	480	350	408	230	270	285	335	275	330	305	360
Coal, Stoker	420	475	320	390	---	---	---	---	260	305	275	365
Oil	385	410	260	290	200	232	230	255	220	248	240	270
164,000 lb/hr [2]												
Coal, Pulverized	345	280	190	230	142	170	165	195	160	191	170	210
Coal, Stoker	242	280	180	232	---	---	---	---	149	180	158	193
Oil	230	245	150	170	135	155	145	160	137	157	145	167
37,000 lb/hr [3]												
Coal, Pulverized	---	---	---	---	---	---	---	---	---	---	---	---
Coal, Stoker	76	85	60	55	---	---	---	---	55	63	56	64
Oil	77	81	46	51	55	61	---	---	52	58	54	60

[1] Divide costs by 13 to obtain cents/10^6 Btu

[2] Divide costs by 5.0 to obtain cents/10^6 Btu

[3] Divide costs by 0.67 to obtain cents/10^6 Btu

energy to decompose the NO spontaneously. Therefore, the concentration of the NO remains "frozen" as the flue gases are cooled.

The normal range of NO_x concentration in the flue gas is approximately 300 to 700 ppm. At these low concentrations, other flue gas constituents such as CO_2, SO_2 and O_2 interfere with NO_x removal processes using sorption, scrubbing and catalytic conversion techniques. Several NO_x removal processes are being investigated. However, all of them are still at the laboratory bench stage of development and are not available for full-scale installation.

The SO_2 removal processes which are now available are not expected to reduce the NO_x emissions significantly under normal operating conditions, although Combustion Engineering, Inc. claims a reduction of approximately 20 percent with their limestone scrubbing process [5-27]. Since the NO_x absorption depends primarily on the ratio of NO to NO_2 in the gas, this indicates that other alkaline SO_2 scrubbing processes would obtain approximately the same NO_x removal efficiency.

A more sophisticated process approach to the problem is put forth by Tyco Laboratories [5-22]. This treatment of flue gases will remove both SO_2 and NO_x and, in so doing, produce both sulfuric and nitric acids. While based soundly on known reactions and equipment types, it has only had "mini-pilot" scaling and is not yet ready for utility-type operations. It is not applicable to intermediate-size boilers at this time and its future applicability is questionable because of its complexity and chemical-plant orientation.

However, the oxides of nitrogen can be minimized or controlled more effectively by controlling the variables affecting their formation. For stationary fossil-fuel burning equipment, these variables are flame temperature, excess combustion air and the nitrogen in the fuel. This attack on NO_x appears to be the most promising at this time since significant reductions in NO_x emissions have already been demonstrated on utility-size combustion equipment, and is further discussed in Section D, following, and evaluated in Section VI.

D. COMBUSTION DESIGN

1. Summary

Techniques for reduction of emissions by combustion modification fall into three major classes which are listed below:

(a) Use of combustion additives
(b) Changes in combustor design
(c) Use of modified burners

Section VI details the effects and costs of applying these methods, and, in anticipation of the results, a brief statement is warranted here to provide perspective. With respect to SO_2, these techniques have no effect on emissions. For particulates, while they do not approach the capabilities of fuel switching or flue gas treatment, they can be of benefit and must be considered. In NO_x emissions, some of these techniques are of distinct benefit and hold, in fact, the greatest present promise of emissions reduction.

2. Combustion Additives

As an approach to improving combustion and reducing pollutants, total effort in the field of combustion additives has been small when measured against development programs in equipment and fuels. Perhaps it is because the concept has often been viewed as black art, in this case changing obnoxious chemicals into harmless ones. However, in today's view of the pollution situation, the use of chemical additives to reduce particulate, sulfur oxide and nitrogen oxide emissions from furnaces is a concept which deserves to be evaluated, particularly for small and medium size installations where flue gas treatment systems requiring substantial capital expenditure are not likely to be economically feasible.

The purpose here is to survey and evaluate additives presently used or proposed for use in furnaces. These additives are classified according to the air pollutant that they are designed to abate, namely: particulates, nitrogen oxides and sulfur oxides. No attempt is made to distinguish compounds added in small quantities (e.g., catalysts) from those added in larger amounts (e.g., reactants, diluents). A list of typical additives presently in use showing supplier, the amount added and costs is presented in Table 5-14. The table is, by no means, all-inclusive; it is only representative and approximate.

a. Effects on Particulate Emissions

The organometallic additives (e.g., methyl cyclopentadienyl manganese tricarbonyl) which are claimed to reduce carbonaceous particulate emissions from furnaces apparently function as combustion catalysts, speeding the combustion (although their exact role is not clearly understodd). As well as reducing soot formation, these additives may also reduce levels of carbon monoxide and hydrocarbon emissions.

Generally these additives have been utilized in oil combustion systems but these compounds should function equally well for gaseous fuels. The effect of additives on pulverized coal combustion has not been reported.

Reliable data on additive loading and effectiveness in reducing particulate emissions is sparse. About the only information generally available are manufacturers' claims of additive effects and recently the work done at NAPCA [5-28,5-29]. Published results [5-29] indicate that with only about 10% of the over 200 additives tested were reductions in particulate emissions observed. Moreover, it is claimed that under ideal laboratory conditions, burner modifications could produce greater reductions in particulates than the most effective additives.

Additive loadings used in the NAPCA study were high, varying from 1 lb additive/500 lb fuel to 1 lb additive/9000 lb fuel. These loadings exceed typical manufacturer recommended loadings as shown in Table 5-14. Such loadings could result in considerable emissions of toxic metallic particulates [5-29]. The effect on ambient conditions of these emissions have not as yet been ascertained.

TABLE 5-14

COMBUSTION ADDITIVES
Typical Examples and Applications

Additive	Purpose of Use	Suppliers	Approximate Cost	Approximate Loading	Approximate Cost
Dearsol 30	Dispersant and combustion catalyst	Dearborn Chemical Div. of W. R. Grace & Co.	\$0.35/lb	1 qt/1000 gal fuel	\$0.005/10^6 Btu
Dearsol 35	Combustion catalyst	Dearborn Chemical	\$0.25/lb	1 qt/1000 gal fuel	\$0.004/10^6 Btu
Combustion Improver CI2	Combustion catalyst, corrosion inhibitor	Ethyl Corporation	\$2.00/lb	9.4 lb/1000 bbl	\$0.003/10^6 Btu
Apollo MC-7	Combustion catalyst, corrosion inhibitor	Apollo Chemical Corporation	\$2.00/lb	1 gal/1000 bbl	\$0.003/10^6 Btu
LiquiMag	SO_3 removal, corrosion control	Basic Chemical Company	\$0.14/lb	1 lb MgO per lb V_2O_5 in fuel	\$0.0045/10^6 Btu Basis: 600 ppm V_2O_5 in oil

The costs and quantities added are not exact and are meant to be representative. Loading and costs can vary widely above and below the figures quoted. Costs represent the cost of chemicals only, not combustion system modifications, nor do they reflect any cost of disposal or credit for recovery of a saleable product.

A second class of additives, presently used to reduce soot emissions, function by changing the pumping and atomizing characteristics of heavy fuel oils. Some of these additives are dispersants for paraffinic and asphaltenic compounds in the fuel oil [5-30] and may function at very low concentration levels (below 100 ppm). Others reduce the viscosity of heavy oils and still others act by removing or emulsifying water. The overall aim is to produce a more uniform dispersion of fine oil droplets which leads to better combustion.

With coal, most of the particulate emission is fly ash which may be several weight percent of the fuel depending on the fuel and type of firing. No additive exists to remove these particles although one could conceive of one which would enhance agglomeration of the ash particles, causing them to fall to the bottom of the furnace or allow them to be removed more easily with existing dust removal equipment. A second type of additive might function by changing the electrical resistivity of the particles thereby increasing the efficiency of electrostatic precipitation.

b. Effects on Nitric Oxide Emissions

There are no additives which are currently in commercial use to reduce nitric oxide emissions from stationary combustion equipment. Combustion system or combustion process modifications have been suggested as the most promising alternatives. By reducing either the flame temperature, the time at high temperature or the oxygen concentration, nitrogen oxide emissions can be reduced several fold.

A possible way to reduce nitrogen oxide emissions from flames is to inject an inert diluent with the fuel or air in sufficient quantity to lower the maximum flame temperature attainable in the system. Water, particularly liquid water (making use of the latent heat of vaporization), is an ideal candidate since it is inexpensive, non-toxic, easy to inject; it is already present in internal combustion engines and it has been reported that, upon water injection, nitrogen oxides were reduced, engine power was actually increased, and specific fuel consumption decreased slightly. Similarly, the results of NAPCA [5-29] on a series of tests with water-in-oil emulsion fuels have indicated a decrease in the oxides of nitrogen as the water concentration was increased from 0 to 25%. However, particulate emissions increased simultaneously.

c. Effect on Sulfur Oxide Emissions

Perhaps the most effective use of additives, at the present time, has been demonstrated in the reduction of sulfur oxide emissions.

Successful additive action has been experienced in residual oil fired large boilers wherein finely divided MgO additive suspended in light oil is simultaneously injected at a controlled rate into the furnace. The sulfur trioxide, SO_3, emission is decreased, corrosion is reduced substantially, the ash formed on tubes is soft, dry and easily removed. If the fuel contains vanadium, an ash rich in V_2O_5 is obtained and can be sold to more than offset the cost of MgO addition [5-31].

The effect of the additive is considered to be two-fold. First it is considered to retard the oxidation of sulfur dioxide to sulfur trioxide by inhibiting the action of low concentration flue gas components (e.g., iron oxide, sodium salts, vanadium pentoxide) which act as oxygen-carrier catalysts in the reaction; and secondly the additives react with SO_3 producing the sulfate salt.

Many of the manganese-containing additives which are effective in reducing particulate emissions, have also been demonstrated to reduce SO_3 production [5-32,5-33] and it is speculated that these compounds act as catalyst inhibitors in a manner similar to the magnesium compound. Use of organic additives to gain the same sulfur oxide reactions has also been reported [5-34].

Anhydrous ammonia has been added to stack gases of industrial boilers to remove SO_3 and some SO_2 by forming ammonium sulfate and sulfite. The chemical cost is very high and undesirable salt deposits on stacks, ducts and fans build up very rapidly.

The previous section on flue gas treatment has already discussed the processes in which additives are introduced into the combustor to react with SO_2 producing a less offensive or more easily removed compound. These additives are finely ground particles of the oxides and carbonates of magnesium and/or calcium (e.g., limestone, dolomite, lime) [5-35]. These additives schemes are still undergoing tests and several problems have arisen. The additives meet the economic requirement of being relatively inexpensive, particularly dolomite, but up to twice the stoichiometric amount (based on S in the fuel) must be added to have appreciable effect. The particles react slowly with SO_2 even when finely ground so that residence time in the conventional combustion system is inadequate for complete reaction. The reaction proceeds best at intermediate temperatures; at lower temperatures the rate is low, at higher temperatures the particles are physically degraded. Even at very long residence times, the particles have a substantial unreacted fraction. The principal effect of the additive is to change a gaseous emission problem, increasing the load on cyclones and precipitators and posing a solid waste problem after removal from the flue gas.

d. STRAT Input Data

From the foregoing it will be understood that use of specific estimates with respect to the efficacy and cost of combustion additives is hazardous and vulnerable, perhaps more so than any other aspect of this report. The available information is primarily from the manufacturers, with only a limited amount of independent data from a narrow range of equipment and operations.

Nevertheless, this strategy must be qualified because it cannot be dismissed a priori. It appears within the range found in the literature to employ in the program the following values as being attainable in 1975:

(1) 50% reduction in particulate emissions
(2) 0.3 cents per million Btu

3. Combustion Design

a. General

Based on present knowledge and technology, the attack on NO_x emissions is likely to be different from that on particulates and SO_x. For the latter two, present sources and foreseeable progress appears to lie in fuel switching and/or flue gas treatment, although a certain amount of unburned carbon particulate emissions and SO_3 production probably will be reduced by redesign of the combustion package. For NO_x, on the other hand, redesign of the combustion package offers the greatest promise of improvement and will probably include changes in fuel/air mixing and metering, burning mechanisms, the furnace envelope and combustion controls.

The following sections discuss the application of combustion design modifications as a means of reducing emissions. Application of modifications to each of the three major pollutants will be considered separately.

b. Particulates

The combustion package that has evolved over the years has resulted in generally favorable, i.e., low emission rates of particulates -- based on reasonable assumptions of equipment age, operations, maintenance and loading. Given the preceding, gas and distillate oil produce no significant problems, residual oil is not of too much concern, and coal results in an emissions situation that is real but one which can well be handled with existing equipment. The trend of coal firing equipment (from stokers to pulverized firing and the introduction of cyclone burners) has changed the nature of particulate emissions, but not the basic scope and nature of the control problem.

c. Sulfur Oxides

Sulfur in the fuel must appear after combustion substantially as sulfur oxides in the flue gas. (The only minor qualification is that in coal fired units, a small percent of the sulfur is found in the ash.) Perhaps 2-3% of these sulfur oxides will be SO_3, with the remainder as SO_2.

There are no known or proposed methods of combustion design that can change the basic relationship. However, known techniques are being studied to affect a change in the seemingly minor SO_3 formation. In residual oil firing, and sometimes coal also, SO_3, fly ash and water vapor in low temperature flue gases combine to form what is termed "acid smut". Fall-out and settling of this material is of considerable nuisance and damage potential because it is both dirty and acidic.

There is evidence that combustion design, particularly low excess air, can be beneficial in decreasing the SO_3 fraction of the total sulfur oxides. It is not presently possible to quantify this change; in fact there is not sufficient information as to the formation and proportions of SO_3 in the boiler, the stack and atmosphere.

This area has not received much attention to date because the "acid smut" problem is not too widespread, instrumentation is not available, and the low excess air technique is not yet widely understood or employed.

d. Nitrogen Oxides

It is in the abatement of NO_x that combustion design becomes a significant strategy -- and, as mentioned above, this is a fortuitous situation since the other programs of fuel switching and flue gas treatment are inadequate in their effect on NO_x emission.

The study done by Esso Research and Development Company for NAPCA "Control Techniques for Nitrogen Oxide Emissions from Stationary Sources" is the most recent and comprehensive view of the subject and the recommendation and analysis herein follow, generally, that work [5-36].

(1) Low Excess Air (LEA)

This technique originated in Europe on large boilers as an economy measure since draft fans and fan power can be substantial in cost in the utility boiler size range. It was found that employing 5% or less excess combustion air, rather than the usual 20-30%, had the side effect of reducing corrosion because of lower SO_3 formation; it was also noted that NO_x formation was markedly decreased. Development toward understanding and implementation of this concept has taken place, although not with any general evidence of great urgency. Principal attention in the United States has been directed to utility boilers, particularly in the Los Angeles and surrounding area.

Despite the lack of application to small watertube equipment and data therefrom, it appears reasonable to employ lower emissions factors for such equipment in setting 1975 emissions loadings. It is less certain, but still within reason, to employ the same factors for the cast iron and firetube equipment. Being much smaller units, development at an accelerated pace and reasonable expense is possible. Therefore, knowledge of the state of the art as practiced in large boilers has been extrapolated to all equipment of the intermediate-size category. This is manifest as a reduction of 33% in NO_x emissions which figure has been used in the cost effectiveness analysis.

The mechanics of implementing low excess air involve carefully metering combustion air and fuel, measuring either CO_2 or O_2 (or perhaps NO) in the flue gas, and introducing some feedback mechanism from this last measurement to effect control over the fuel/air ratio. In large boilers, all of the above may be part of the standard design of the installation for purposes of economic operation, effecting load changes, minimizing plume opacity and other operational goals. Nevertheless, operation at low excess air levels down to about 2% is not conventional and requires operator training and verification of instrument accuracy.

Accomplishing the same results on progressively smaller boilers very likely will require increasing cost of instruments and controls and training of operators, or of supervisors and maintenance personnel where boilers are unattended.

The diagram below (Figure 5-10, showing a generalized relation between NO_x and excess air) illustrates why careful operation is important if NO_x reduction goals are to be reached. As excess air is reduced from the conventional high range, emission reduction is not too significant until about the 5% is reached. Optimum operation may lie in the 1-2% range. Lower than this risks danger of smoke (due to unburned carbon), CO (due to incompletely burned carbon) and even explosions (due to poor fuel/air mixing). Excellent fuel/air mixing at each burner and uniformly across the furnace is of greatest importance. Smoke and CO, in addition to their pollution aspects, represent furnace efficiency loss.

Because of the importance of fuel/air mixing and control, it becomes apparent that gas as a fuel is the easiest to adapt to this strategy; oil is not too difficult although not as simple as gas. Coal, however, does not fit the picture because of this difficulty. Some reduction in NO_x through excess air reduction is possible especially with pulverized coal firing, but much development would be required before the gains here will match those with oil, much less gas.

(2) Flue Gas Recirculation (FGR)

A second technique for reducing NO_x involves bringing a portion of the combustion flue gas back to the combustion chamber as part of the combustion air [5-36]. This appears to reduce excess air, with the effects as described above, and also to reduce flame temperatures, which has been shown to be an effective mechanism.

Again, virtually the only work that has been done in this area has been with utility size equipment. Implementation of this strategy is not too difficult, involving a flue gas recirculation fan, duct work and controls. The fan and control dampers operate, of course, in a hot atmosphere, but equipment and design is not new and is readily available. A study by Esso [5-37] has demonstrated that it should not be difficult to transfer this know-how to the small boiler field.

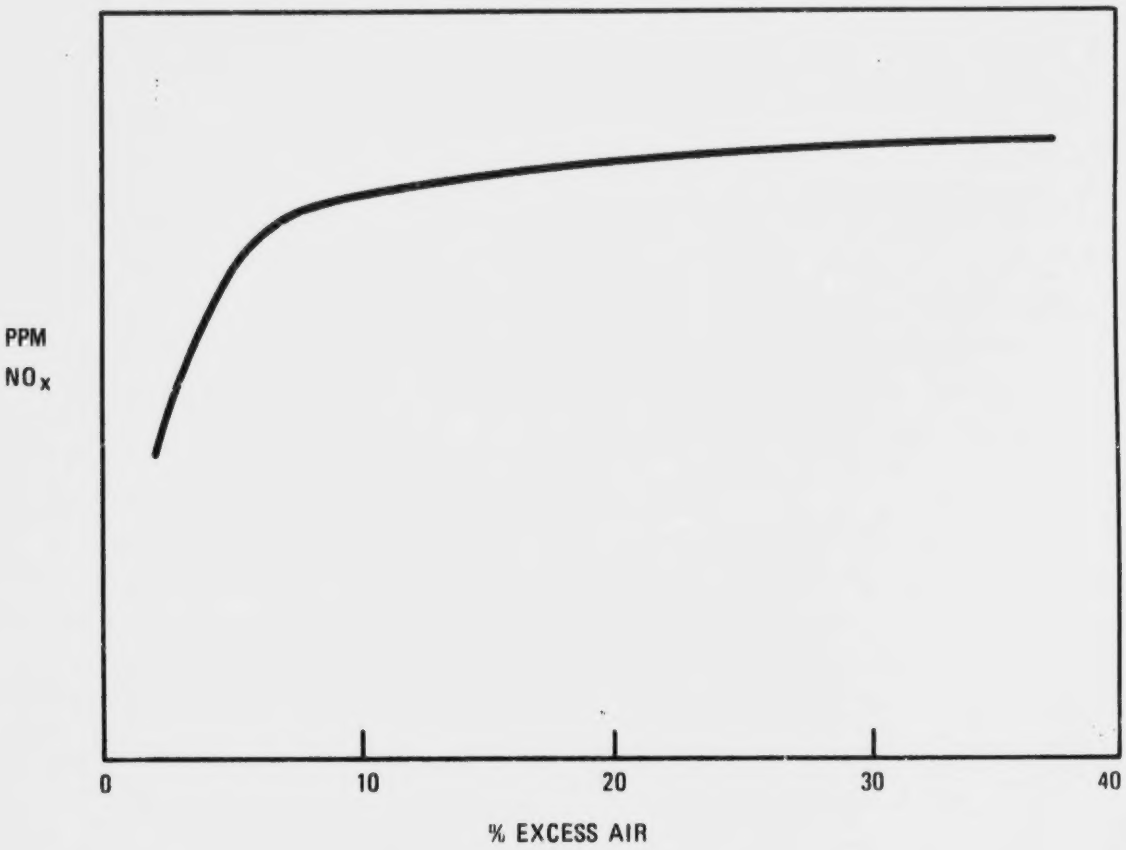


Figure 5-10. Typical NO_x Emissions as Function of Excess Air.

As was done for the low excess air approach, a 33% reduction was assumed as the potential gain in using flue gas recirculation.

(3) LEA Plus FGR

Extension of the above techniques have led to development of boiler operation with both low excess air and flue gas recirculation. This has been successfully demonstrated in commercial equipment and, as a result of the compound effect, a reduction of NO_x emissions by 50% has been assumed for the combined strategy [5-36].

(4) Two-Stage Combustion

One of the advanced concepts summarized by Esso is that of two-stage combustion [5-36]. Work on commercial units has gone forward and a West Coast utility with an NO_x emissions problem has made considerable progress, aided by their boiler manufacturer. At this point, recent field results have merely been confirming the general outline of prospects suggested by Esso.

In operation, the combustion air introduced at the burner is most of, but not the total quantity; therefore, combustion takes place at or slightly below stoichiometric ratio. The balance of combustion air (bringing the total to the level of low excess air) is brought in as secondary air, usually physically above the burners. The overall result is combustion at a low flame temperature and with insufficient air to provide oxygen for formation of high NO_x levels. Obviously, the best possible fuel/air mixing is required if efficiency loss and/or explosions are to be avoided. This implies that gas fuel is the easiest with which to operate.

The work to date has been so restricted, with respect to number of installation and type of fuel, that its translation into intermediate-size boilers with a variety of fuels appears to be some distance away. Therefore, no application was made in this report of two-stage combustion as a method of reducing NO_x emissions.

(5) Economic and Operating Characteristics

It is, as noted, difficult to gather much pertinent data on cost or pollutant reduction for either low excess air or flue gas recirculation as applied to intermediate-size boilers. The values chosen for reduction efficiency were 33% reduction for either approach used singly, and 50% reduction for combination of the two. These values appear conservative based on the limited evidence available.

Obtaining capital costs is more difficult. On the basis of costs prepared by Esso [5-36] for larger systems, and engineering estimates provided by Riley-Stoker [5-4] and other manufacturers, the following capital estimates were derived and used in the analysis.

TABLE 5-15

ADD-ON COST OF COMBUSTION MODIFICATION

	Cost Per Boiler		
Boiler Size	LEA	FGR	Both
WT-1 (< 100,000 pph)	\$3,000	\$ 6,000	\$ 8,000
WT-2 & 3 (100,001-500,000 pph)	4,000	20,000	22,000
Firetube and cast iron	3,000	3,000	4,200

A low annualization factor of 10% has been applied against the above capital cost, because of the effects of assuming the life of such accessories will equal that of the boiler and because of low maintenance requirements.

The addition to the boiler plant that is essential to operation with either of these modes is a flue gas instrument that will indicate excess air (as oxygen or CO_2 in the gases). This will modulate the fuel/air ratio for LEA operation, most likely by damper control on the forced draft fan output. For FGR operation, the requirements include ductwork, a small fan, and volume control to bring combustion gases back to the wind-box and/or combustion zone of the boiler.

As explained above, the original attraction of LEA was economy. Insufficient background is available on operations with intermediate boilers with LEA or FGR for a firm determination of operating costs. It was assumed that LEA will realize enough savings through fuel economy, in the large sizes to offset annualized capital costs. In the smaller sizes, with lower load factors, the savings may not be adequate and the annualized capital cost was set equal to the total operating cost. For FGR, a similar coarse evaluation was assumed.

4. Other Developments

a. Oil Burners

There has been gradual improvement in emissions from oil burning equipment over many years. This short discussion of recent developments is included as background.

In 1960, the American Petroleum Institute (API) sponsored a program to initiate and coordinate research on small oil burners which use No. 1 and No. 2 distillate fuel oil. Most of the recent developments on small burners in the U.S.A. have arisen from this program. These results are summarized in the Annual API Research Conference on Distillate Fuel Combustion up to 1966 [5-38 to 5-43]. Very recently, work on small burners has been extended by the National Oil Fuel Institute, Inc. (NOFI) and reported in their New and Improved Oil-Burner Equipment Workshops [5-44]. Reports of valuable investigations by NAPCA researchers have been reported at these NOFI workshops and elsewhere [5-45 to 5-47].

Unfortunately, the earlier references were more concerned with aspects of equipment efficiency, cost, maintenance, etc., and only the recent literature has evidenced principal concern about pollution and its possible abatement. Also, most burner development that has been published relates to small sizes -- essentially residential -- and the potential application to the intermediate-size boiler field is not at all well documented.

Much development of large burners (for intermediate-size boilers and larger) is done by the boiler manufacturers or by burner manufacturers competing for boiler business. Little development has been directed toward pollution abatement aspects of this equipment, probably because this aspect had little value in the market place, historically.

Discussions with boiler companies [5-48,5-49] indicate considerable interest in the Forney Verloop and similar oil and gas burners. This is a European development which shows promise of low NO_x emissions. In direct discussion with the manufacturer [5-50], no specific claims were made for the present, at least with respect to a concentration of NO_x in the flue gas. It was stated that work along these lines has been funded and test programs are progressing in Holland. Low excess air approaches in oil-fired boilers depend in part on the development of more effective burners.

b. Fluidized Bed Combustors

There has been considerable interest in fluidized bed burners in the U.S., U.K., and Russia [5-51 to 5-54]. Two major goals of research in this area have been lower plant cost for utility boilers and reduced sulfur oxide emission. Most of the work has been cone on coal in the U.K. and U.S. but residential fuel oil has been used as well. The results obtained have been with small and medium sized laboratory burners, with short run times [5-51 to 5-53]. A solid absorbent for SO_2 (e.g., limestone) can be mixed with or used as the fluidized solids. Essentially all of the SO_2 from a high sulfur fuel (> 3%) can be removed with substantial utilization (60%) of the absorbent.

In theory, this concept should prove to be an advance with respect to oxides of nitrogen because of lower combustion temperatures, but results to date have not shown this characteristic [5-55], possibly because local hot zones with excess oxygen exist in the bed. Particulates may be higher due to attrition of the SO_2 absorbent or other solids in the bed. Some work on control and burner stability exists in the Russian literature [5-56].

E. STRATEGY CHARACTERISTICS

Those individual control means that appeared to have merit and were in a state of development where cost and operating data were available or could be estimated, were evaluated quantitatively to determine (1) their effectiveness in reducing emissions and (2) the capital and operating costs associated with their application. The most promising of the large number that were examined are tabulated in Appendix C.

The evaluation of individual strategies was carried out using the STRAT program which contained subroutines with the operating cost data presented above. Cost-effectiveness analyses were done on the 1975 projections on the basis of immediacy. After selection of the subsets of boilers and control approaches, the STRAT program was run to provide as output data:

(1) Number of units involved in strategy
(2) Total reduction of pollutants in tons per year
(3) Total annual operating cost
(4) Total capital cost
(5) Specific cost in dollars per pound of pollutant abated

These data, plus a strategy identification description, are presented in Appendix C for the strategies which appeared to have potential value.

REFERENCES TO SECTION V

5-1. The Fuel of Fifty Cities, Ernst & Ernst, November 1968.

5-2. Steam-Electric Plant Factors, National Coal Association, Washington, D.C., 1968.

5-3. Desulfurization Costs Residual Fuel Oil, Bechtel Corp. Report for API, February 1967.

5-4. Riley Stoker Corp., Progress Report on Sub-Contract, January 1970.

5-5. Stone & Webster Engineering Corp., Progress Report on Sub-Contract, September 1970.

5-6. Smith, M.C. and Salerno, A.A., "Engineering for Low Sulfur Fuels", ASME Paper 68-WA/APC-1.

5-7. Anon., Control Techniques for Particulate Air Pollutants, NAPCA Pub. No. AP-51, U.S. Dept. of HEW, Public Health Service, Consumer Protection and Environmental Health Service, 1969.

5-8. Riley Stoker Corp., Progress Report on Sub-Contract, March 1970.

5-9. Western Precipitation Div., Personal Communication, May 1970.

5-10. Gorman, P., Midwest Research Inst., Kansas City, Mo., Personal Communication, July 1970.

5-11. Semrau, K.T., Marynowsk, C.W., Lunde, K.E., and Lapple, C.E., "Influence of Power Input on Efficiency of Dust Scrubbers", I&EC 50 (11):1615-1620, November 1958.

5-12. Jonakin, J. and McLaughlin, J.F., Operating Experience with the First Full Scale System for Removal of SO_2 and Dust from Stack Gas, presented at American Power Conference, Chicago, Illinois, April 22-24, 1969.

5-13. Hall, H.J., Recon Systems, Inc., Princeton, N.J., Personal Communication, July 1970.

5-14. Lynch, C.E., "On-Line Experience with Operation of Electrostatic Precipitators on Oil-Fired Boilers", presented at New England Section (APCA), Hartford, Conn., April 16, 1969.

5-15. Ramsdell, R.G. Jr., "Design Criteria for Precipitators for Modern Central Station Power Plants", Proceedings American Power Conference, pp 444-449, 1968.

5-16. Billings, C.E., GCA Corp., Bedford, Mass., Personal Communication, July 1970.

REFERENCES (cont.)

5-17. Dennis, R. and Bernstein, R.H., "Engineering Study of Removal of Sulfur Oxides from Stack Gases", Report for Committee for Air and Water Conservation, American Petroleum Inst., August 1968.

5-18. Willett, H.P., Quig, R.H. and Shah, I.S., "Venturi Scrubbing for SO_2 and Fly Ash Removal at Power Plant Sites with Centralized Reactant Reprocessing", presented at New England Section, APCA, Hartford, Conn., April 16, 1969.

5-19. "Sulfur Dioxide Removal from Power Plant Stack Gas Conceptual Design and Cost Study Sorption by Limestone or Lime Dry Process", TVA Report, 1968.

5-20. Maurin, P.G. and Jonakin, J., "Removing Sulfur Oxides from Stacks", Chemical Engineering, p. 173, April 27, 1970.

5-21. Plumley, A.L., Whiddon, O.D., Shutko, F.W. and Jonakin, J., "Removal of SO_2 and Dust from Stack Gases", presented at American Power Conference, Chicago, Illinois, April 25-27, 1967.

5-22. McLaughlin, J.F. and Jonakin, J., "Operating Experience with Wet-Dolomite Scrubbing", Annual Meeting, APCA, June 1969.

5-23. Oldenkamp, R.D. and McKenzie, D.E., "The Molten Carbonite Process for Control of Sulfur Oxide Emissions", North American Rockwell Corp., Atomic International Div.

5-24. Humphries, J.J., Zdonik, S.B. and Parsi, E.J., "Economic Factors in the Capital and Operating Costs of the Stone & Webster/Ionics SO_2 Removal and Recovery Process", presented at AIChE Symposium Chicago, Illinois, November 29-December 1, 1970.

5-25. Terrana, J.D., Hiller, L.A., "New Process for Recovery for SO_2 from Stack Gases", Wellman-Lord, Inc., Florida.

5-26. Stone & Webster Engineering Corp., Sub-Contract, September 1970.

5-27. Saunders, E., Walitt, A., Rissman, E. and Keilin, B., "The Recovery of Nitric and Sulfuric Acids from Flue Gases", presented at AIChE, Cleveland, Ohio, May 5, 1969.

5-28. Martin, G.B., "Use of Fuel Additives and Combustion Improving Devices to Reduce Air Pollution Emissions from Domestic Oil Furnaces", presented at the Third New and Improved Oil Burner Workshop of NOFI, Hartford, Conn., September 23-24, 1970.

REFERENCES (cont.)

5-29. Martin, G.B., Wasser, J.H. and Hangebrauck, R.P., "Status Report on Study of Effects of Fuel Oil Additives on Emissions from an Oil-Fired Test Furnace", presented at Annual Meeting of The Air Pollution Control Assoc., St. Louis, Mo., June 14-19, 1970.

5-30. "The Treatment of Residual Fuel Oils", Dearborn Chemical Division, W.R. Grace Co., Merchandise Mart, Chicago, Ill., Technical Bulletin 12101.

5-31. Exley, L.M., Tamburrino, A.E. and O'Neal, A.J., Jr., "LILCO Trims Residual Oil Problems", Power, 110 (4), pp. 69-73, April 1966.

5-32. Belyea, A.R., "Manganese Additive Reduces SO_3", Power, November 1966.

5-33. Kukin, I., "Advances in the Use of Chemical Treatment in Air Pollution Reduction Programs", presented at the Rocky Mountain Regional Meeting, National Petroleum Refiners Association, Oct. 2-3, 1968.

5-34. Bartoletti, M., and Wichser, B., "Recent Experiences with Organic Additives to Prevent Corrosion and Fouling of High and Low Temperature Surfaces in High-Pressure Steam Generators", Combustion, 67 (11), pp. 29-32, May 1967.

5-35. "Control Techniques for Sulfur Oxide Removal", U.S. Department of Health, Education and Welfare, NAPCA Publication No. AP-52, Jan. 1969.

5-36. Bartok, et al., "Systems Study of NO_x Control Methods for Stationary Sources," Esso R&D Co. (NAPCA Contract PH 22-68-55), November 1969.

5-37. Andrews, R. L., Siegmund, C. W., and Levine, D. G., "Effect of Flue Gas Recirculation on Emissions from Heating Oil Combustion," Paper 68-21, presented at the 61st Annual Meeting of APCA, St. Paul, Minnesota, June 23-27, 1968.

5-38. Proceedings: First API Research Conference on Distillate Fuel Combustion, API Publication 1541, March 1961.

5-39. Proceedings: Second API Research Conference on Distillate Fuel Combustion, API Publication 1701, June 1962.

5-40. Proceedings: Third API Research Conference on Distillate Fuel Combustion, API Publication 1702, June 1963.

5-41. Proceedings: Fourth API Research Conference on Distillate Fuel Combustion, API Publication 1703, June 1964.

5-42. Proceedings: Fifth API Research Conference on Distillate Fuel Combustion, API Publication 1704, June 1965.

5-43. Proceedings: Sixth API Research Conference on Distillate Fuel Combustion, API Publication 1705, June 1966.

5-44. Proceedings: New and Improved Oil Burner Equipment Workshop, NOFI Technical Publication 106ED, September 1968.

5-45. Wasser, J.H., Hangebrauck, R.P. and Schwartz, A.J., APCA Paper No. 67-124, 1967.

5-46. Martin, G.B., Wasser, J.H., and Hangebrauck, R.P., "Status Report on Study of Effects of Fuel Oil Additives on Emissions from an Oil-Fired Test Boiler", APCA Paper No. 70-120, St. Louis, Mo., June 1970.

5-47. Howekamp, D.P. and Hooper, M.H., "Effects of Combustion-Improving Devices on Air Pollutant Emissions from Residential Oil-Fired Furnaces", presented at NOFI Burner Workshop, Tarrytown, N.Y. September 24-25, 1969.

5-48. Riley Stoker Corp., Personal Communication.

5-49. Foster Wheeler Corp., Personal Communication.

5-50. Forney Engineering Co., Personal Communication.

5-51. Wright, S.J., Ketley, H.C. and Hickman, R.G., J. Inst. Fuel, 235-240, June 1969.

5-52. McLaren, J. and Williams, D.F., J. Inst. Fuel, 303-308, August 1969.

5-53. Bishop, J.W., Robinson, E.B., Ehrlich, S., Jain, A.K. and Chen, P.M., Preprint paper 68-WA/FU-4, ASME Meeting, New York, December 1968.

5-54. Rubtsov, G.K. and Syromyatikov, N.I., Izv. Akad. Nauk. SSR, Met. i Gorn. Delo., 69-74, 1964.

5-55. Henschel, D.B. and Turner, P.P., "Review of Fluidized Bed Combustion: Anti-Pollution Characteristics and Economics", DPCE of NAPCA, April 1969.

5-56. Lodyseva, M.S. and Burovoi, I.A., Zhur. Vsesoyuz. Khim. Obshchestva im. D.I. Mendeleeva, 6, 553-556, 1961.

ADDITIONAL REFERENCES (UN-CITED) FOR PARTICULATES CONTROL

Anon., *A Compilation of Selected Air Pollution Emission Control Regulations and Ordinances*, U.S. Dept. of HEW, Public Health Service Pub. No. 999-AP-43, pp. 17-34, 1968.

Anon., *Air Quality Criteria for Particulate Matter*, NAPCA Pub. No. AP-49, U.S. Dept. of HEW, Public Health Service, Consumer Protection and Environmental Health Service, p. 27, 1969.

Anon., *Criteria for the Application of Dust Collectors to Coal-Fired Boilers*, IGCI/ABMA Joint Technical Committee Survey, 1968.

Anon., *How to Reduce Stack Dust from Small Stationary Plants*, Bituminous Coal Research, Inc., pp. 4-5, 1952.

Anon., *Industrial Ventilation*, American Conference on Governmental Industrial Hygienists, Sec. 11, p. 22, 1968.

Boer, E.J. and Porterfield, C.W., *Dust Emissions from Small Spreader-Stoker-Fired Furnaces*, ASME, pp. 7-9, 1953.

Cuffe, S.T. and Gerstle, R.W., *Emissions from Coal-Fired Power Plants: A Comprehensive Summary*, U.S. Dept. of HEW, Public Health Service Pub. No. 999-AP-35, Consumer Protection and Environmental Health Service, p. 17, 1967.

Culhane, F.R., "Production Baghouses", *Chemical Engineering Progress*, pp. 65-73, Vol. 64, No. 1, January 1968.

Edmisten, N.G. and Bunyard, F.L., "A Systematic Procedure for Determining the Cost of Controlling Particulate Emissions from Industrial Sources", JAPCA *20* (7):446-452, July 1970.

"Fabric Filter Systems, Series H", Environmental Research Corporation, Pollution Control Div., Bulletin 521.

Holton, W.C. and Engdahl, R.B., *Methods of Reducing Dust Emission from a Spreader-Stoker-Fired Furnace*, ASME, Paper No. 51-SA-20, p. 9, 1951.

Kaiser, E.R., *Factors Affecting Dust Emission from Boiler Furnaces*, Bituminous Coal Research, Inc., p. 11, 1957.

Kopita, R. and Gleason, T.G., "Wet Scrubbing of Boiler Flue Gas", *Chemical Engineering Progress*, pp. 74-78, Vol. 64, No. 1, Jan. 1968.

Moore, W.W., *Reduction of Ambient Air Concentration of Fly Ash -- Present and Future Projects*, Proceedings: The Third National Conference on Air Pollution, Wash., D.C., pp. 170-178, Dec. 12-14, 1966.

ADDITIONAL REFERENCES (UN-CITED) FOR PARTICULATES CONTROL (cont.)

Sargent, G.D., "Dust Collection Equipment", *Chemical Engineering*, pp. 130-150, January 27, 1969.

Semrau, K.T., "Correlation of Dust Scrubber Efficiency", JAPCA *10* (3), pp. 200-207, June 1960.

Smith, J.L. and Snell, H.A., "Selecting Dust Collectors", *Chemical Engineering Progress*, pp. 60-64, Vol. 64, No. 1, January 1968.

Smith, W.S. and Gruber, C.W., *Atmospheric Emissions from Coal Combustion: An Inventory Guide*, NAPCA Pub. No. AP-24, U.S. Dept. of HEW, Public Health Service, Div. of Air Pollution, pp. 57-60, 1966.

Stairmand, C.J., "Removal of Grit, Dust and Fumes from Exhaust Gases from Chemical Engineering Processes", *The Chemical Engineer*, Dec. 1965.

Stairmand, C.J., "The Design and Performance of Modern Gas-Cleaning Equipment", *Journal of the Institute of Fuel*, February 1956.

Walker, A.B. and Frisch, N.W., "Scrubbing Air", *Science and Technology*, pp. 18-27, Nov.-Dec. 1969.

ADDITIONAL REFERENCES (UN-CITED) FOR SO_2 CONTROL

"The Catalytic Oxidation System for Removing SO_2 from Flue Gas", Sites Horlacher, Baelroter, Bartman (Monsanto) 1968.

"Process Development in Removing SO_2 from Hot Flue Gas" Field and Myers, U.S. Bureau of Mines Rpt. Invest No. 5735.

"Studies on New Method of Removing NO_x and SO_x from Combustion Gases", Rayson and Harkins, Chevron Research, 60th Meeting APCA, 1967.

"Desulfurization of Flue Gas by Active Carbons", Tamura, Z., Hishinuma, Y., Hisamura, T., Vol. 17, No. 9.

"SO_2 Control Processes for Stack Gases Reach Commercial Status", Environmental Science and Technology, 2 (11), p. 994, 1968.

"Federal Research Presses for Sulfur Solution", Coal Research, Spring 1968, No. 29.

"An Appraisal of Air Pollution in the Power Industry", Pirsh, E.A., Rusanowsky, N.P., Young, N.W., American Power Conference, April 1968.

"Simultaneous Removal of SO_2 and NO_x from Flue Gases", Saenz, O., McKee, H.G., Hiser, L.L., and Reinauer, T.V., Southwest Research Institute, Houston, Texas, presented to 61st Annual Meeting APCA, June 1968.

"The Removal of Oxides of Sulfur from Flue Gases", Res. Jour. of Inst. of Fuel, p. 350, March 1953.

"Recovery of Sulfur from Flue Gas by the Use of NH_3: A summary of the Probable Costs of the Process", Craxford, Walker, Jour. Instit. of Fuel, 1952.

"Sulfur Removal: For Air Pollution Control", Frankenberg, T.T., Mech. Eng., p. 36, August 1965.

"Studies of the Removal of SO_2 from Hot Flue Gases as a Measure to Prevent Air Pollution II", Kiyoura, Dr. R., Tokyo Institute of Technology, presented to 60th Annual Meeting APCA, p. 167.

"A review of SO_x Control Research, Diehl, E.K., presented to National Coal Assoc., 1967.

"Air Pollution: The Control of SO_2 from Power Stacks", Part 1, Squires, A.M., Chem. Eng., Nov. 1967.

"The Fundamental Sulfur Fixation by Lime and Magnesia", Battelle Memorial Institute, Columbus Labs., June 1966.

ADDITIONAL REFERENCES (UN-CITED) FOR SO_2 CONTROL (cont.)

"Japan Moves on Desulfurization of Thermal Plants", Yoshimura, J., Electrical World, March 20, 1967.

"The Present Status of Flue Gas Desulfurization", Johswich, F., p. 18, October 1965.

"Air Pollution Casts New Shadows", Electric Light and Power, p. 43, August 1965.

"SO_2 Removal and Recovery from Pulp Mill Power Plants", by Galeano, S.F., Harding, Ph.D., C.I., Air Pollution Research Lab. of U. of Florida.

"SO_2 Stack Gas Gives $(NH_4)_2SO_4$ C&EN, p. 23, June 27, 1966.

"Pollution Control Interrelationships", Gartrell, F.E., Barber, J.C., CEP, Vol. 62, No. 1, October 1966.

"Promise Seen in Stack Gas SO_2 Removal", Oil and Gas Journal, p. 53, May 2, 1966.

"Removal of SO_2 and Fly Ash from Coal Burning Power Plant Flue Gas", Pollock, W.A., Tomany, J.P., Frieling, G., presented to Winter Annual Meeting and Energy Systems Exposition, ASME Publication 66-WRICD-4, Dec. 1966.

"New Stack Gas Process May Cut Costs", Oil and Gas Journal, p. 94, June 1966.

"New Pilot Plants Tackle SO_2 Pollution", CEN, p. 35, July 1966.

"Removal of SO_2 from Flue Gases", Katell, S., CEP 62 (10), p. 67, 1966.

ADDITIONAL REFERENCES (UN-CITED) FOR NO_x CONTROL

Bagwell, F.A., Rosenthal, K.E., Breen, B.P., deVolo, N.B., Bell, A.W., "Oxides of Nitrogen Emission Reduction Program for Oil and Gas Fired Utility Boilers", presented at American Power Conference, Chicago, Ill., April 1970.

Barnhart, D., Diehl, E.K., "Control of Nitrogen Oxides in Boiler Flue Gases by Two-Stage Combustion", presented before the APCA 52nd Annual Meeting, Los Angeles, Calif., June 1959.

Fernandes, J.H., Sensenbaugh, J.D., Peterson, D.G., "Boiler Emissions and Their Control", presented at the Conference on Air Pollution Control, Mexico City, Mexico, April 28, 1966.

Jefferis, G.C., Sensenbaugh, J.D., "Effect of Operating Variables on the Stack Emission from a Modern Power Station Boiler", ASME Paper No. 59-A-308, Annual Meeting, Atlantic City, N.J., November 29 - December 4, 1959.

Poole, A.J., "Applying Oil Burning Equipment to New and Existing Boilers", presented to the American Power Conference, Chicago, Ill., April 23, 1969.

Reese, J.T., Jonakin, J., Caracristi, V.Z., "Prevention of Residual Oil Combustion Problems by Use of Low Excess Air and Magnesium Additive", ASME Paper No. 64-Pwr-3, American Society of Mechanical Engineers, Tulsa, Oklahoma, Sept. 27 - Oct. 1, 1964.

Rochford, R.S., "Multiple-Fuel-Fired Industrial Boilers", Proceedings of the American Power Conference, Vol. XXVI, pp. 672-681, 1964.

Sensenbaugh, J.D., "Formation and Control of Oxides of Nitrogen in Combustion Processes", presented at the Air Pollution Training Course, Robert A. Taft Sanitary Engineering Center, Cincinnati, Ohio, March 3, 1966.

Winship, R.D., Sailer, G., Anderson, P.C., "Industrial Boiler Operation at Low Excess Air", presented at the American Power Conference, Chicago, Ill, April 21-23, 1970.

VI. COST-EFFECTIVENESS ANALYSIS

A. INTRODUCTION

The selection or development of a proper index or format for examining the cost-effectiveness of the broad classes of control strategies described above is made difficult by the complexity of the subject -- intermediate-size boilers; there are so many different parameters involved: pollutant, equipment size and type, fuel, user, etc. Unlike several previous studies oriented toward a single pollutant, or industrial group, this study crosses many bounds. Initially, a strategy analysis was carried out for each of the three pollutants independently. It became evident, however, that the problems and approaches were all deeply intertwined and some combined way of looking at the analysis was needed.

After certain patterns became apparent, a rather simple analytic scheme was adopted wherein the strategies were applied to each broad equipment size and type, separately, and the ensuing percent reductions of the three pollutants were added together as a combined measure of effectiveness.

The final broad strategies are, in actuality, composites of individual control means applied to subsets of the entire group of intermediate boilers. A compilation of the costs and reductions of the individual strategies is presented in Appendix C, with examples showing how the results were obtained.

The economic impact of the strategies has been examined in terms of both initial capital cost and also annual cost. The latter quantity includes such operating costs as fuel, labor, maintenance, water, etc., and the annualized capital cost. The latter factor represents the depreciation and depends on the number of years of useful life assumed and on the cost of money (discount rate). These factors depend on both user and type of equipment, as well as the current economic situation, as described in Section V above.

Exercise of judgment in assessing, a priori, the multitude of strategies leads one quickly to the many positive aspects of fuel switching. The major advantage is the fact that this approach can very largely eliminate, simultaneously, emission of SO_2 and particulates, and make a good showing in total NO_x emissions. Other positive aspects are low capital cost, simplicity of operation, and the fact that a developmental program is not required. Further, the most technologically advanced alternative, flue gas treatment, carries a number of practical or operational handicaps in small-scale applications.

Summation of the particulate, SO_2 and NO_x emissions of the intermediate size boilers shows that almost 83% of the total originates from the watertube design, as was shown in Figure 3-7; also, it is seen that about 78% of total emissions derives from coal fired units, regardless of type. This set of information provided a guide as to where the efforts would be concentrated. The results bear out the early judgments.

B. WATERTUBE BOILERS

1. Fuel Switching

Because of the dominating influence of the watertube boilers as demonstrated above, the first general program must be to effect a fuel switch for this equipment. The results obtained are shown in Table 6-1.

As discussed above, fuel switching is based on the gross regional assumptions that coal-fired equipment would be converted to residual oil firing in the Atlantic (AT) and Southeast (SE) areas (a total of 17 states) and to gas firing in the balance of the 48 states. Further examination of the emissions from residual oil at present sulfur levels and from low sulfur residual (herein taken to be 0.5% or less sulfur by weight) indicates that the latter must be chosen to be an effective SO_2 strategy. In addition, all units presently firing residual oil would switch to low sulfur residual. From the standpoint of price considerations, the basic cost-effectiveness evaluation is based on best

TABLE 6-1

FUEL SWITCHING STRATEGY ON WATERTUBE SIZES

	Emissions (10^6 tons/year)		Individual Pollutant Percent Reduction	Cost* (10^6 \$)	
	1975 Projection	Reduction		Capital	Annual Operating
Particulates					
WT-1	1.421	1.287			
WT-2 & 3	0.561	.496			
FT & CI	0.549	N.A.	--		
Sub-Total	2.531	1.783	70.5		
SO_2					
WT-1	2.410	2.023		235.7	378.3
WT-2 & 3	3.239	2.876		197.4	336.9
FT & CI	1.983	N.A.	--	--	--
Sub-Total	7.632	4.899	64.1	433.1	715.2
NO_x					
WT-1	0.620	0.133			
WT-2 & 3	0.885	0.271			
FT & CI	0.574	N.A.	--		
Sub-Total	2.079	0.404	19.4		
TOTALS	12.242	7.086		433.1	715.2

---

*Costs are placed in table opposite SO_2 control, but are shared by all pollutants.

N.A. = Not applicable.

available knowledge of today's price structure. (The effect of increased price -- virtually inevitable -- of these "clean" fuels is considered below).

2. Flue Gas Treatment

It was found that control of all emissions from watertube boilers, comparable to the results of fuel switching, can be accomplished by means of a flue gas treatment. Wet scrubbing employing a sodium carbonate solution was selected as being optimal. The process was described (as Scheme B) in Section V above. The results of applying this strategy to watertube boilers are shown in Table 6-2.

C. FIRETUBE AND CAST IRON BOILERS

As previously illustrated, these boilers are not a large contributor to overall emissions; nevertheless, they should be included in consideration of strategies, because (1) those that burn coal, while not large, will be obvious local polluters and (2) it is desirable to extend the 55-60% total reduction resulting from watertube strategies alone.

The general discussion of SO_2 control strategies indicates that fuel switching is the only practical control approach for these smallest units of the intermediate-size range. Flue gas treatment in the foreseeable future is found to be uneconomical for firetube boilers and virtually inapplicable for cast iron boilers from the standpoint of unit capital cost, available space in most locations, and competent operating personnel.

As with the watertube class of boilers, fuel switching meets all the requirements of a satisfactory strategy. The details of the switching differ from that used for watertube boilers. Although there will be exceptions, it was assumed that all present coal-fired equipment in the AT and SE regions would be converted to distillate oil rather

TABLE 6-2

FLUE GAS TREATMENT STRATEGY ON WATERTUBE SIZES

	Emissions (10^6 tons/year)		Individual Pollutant Percent Reduction	Cost* (10^6 \$)	
	1975 Trend	Reduction		Capital	Annual Operating
Particulates					
WT-1	1.421	1.364			
WT-2 & 3	0.561	.539			
FT & CI	0.549	N.A.	--		
Sub-Total	2.531	1.903	75.5		
SO_2					
WT-1	2.410	1.975		1576.5	605.2
WT-2 & 3	3.239	3.072		909.0	584.2
FT & CI	1.983	N.A.	--	--	--
Sub-Total	7.632	5.047	66.0	2485.5	1189.4
NO_x					
WT-1	0.620	.124			
WT-2 & 3	0.885	.177			
FT & CI	0.574	N.A.	--		
Sub-Total	2.079	.301	14.5		
TOTALS	12.242	7.251		2485.5	1189.4

---

*Costs are placed in table opposite SO_2 control, but are shared by all pollutants.

N.A. = Not applicable.

than the more expensive and troublesome conversion to low sulfur residual; in other regions the new fuel was chosen to be gas; further all units presently burning residual oil would switch, at negligible cost to low sulfur residual. The results of this strategy are shown in Table 6-3.

D. ALL INTERMEDIATE-SIZE BOILERS

The results show that the fuel switching program is the best route for emissions reduction from all intermediate boilers based on: (1) for watertube boilers, the differential in capital cost requirements compared to flue gas treatment and operating costs and (2) for the cast iron/firetube sizes, the negative practical aspects of flue gas treatment.

The overall results combining the data in Tables 6-1 and 6-3 for intermediate boilers are set forth in Table 6-4.

E. SENSITIVITY TO FUEL PRICE ON THE TRADE-OFF BETWEEN FUEL SWITCHING AND FLUE GAS TREATMENT

Tables 6-1 and 6-2 show that fuel switching has been selected as the preferred strategy for the watertube boilers because its annual operating cost is 60% of that for flue gas treatment. This is the projection to 1975 of present trends of growth and technology, but it is natural to question whether this choice will stand in the face of price trends. To a limited extent it is probably true that overall economic indicators will carry with them costs of both strategies, maintaining approximate advantages. But increased demands on premium fuels, in addition to other influences, have already upset fuel prices.

If fuel prices increase disproportionately, fuel switching would become less advantageous, until a point would be reached where the two strategies would be equal in annual operating cost. This is brought out in Figure 6-1 and identifies this cross-over as being that point in the economy where fuel prices have risen to 175% of the figures used herein. However, in actuality the prices would have to rise still

TABLE 6-3

FUEL SWITCHING STRATEGY ON FT AND CI BOILERS

	Emissions (10^6 tons/year) 1975 Trend	Reduction	Individual Pollutant Percent Reduction	Cost* (10^6 \$) Capital	Annual Operating
Particulates					
WT-1	1.421	N.A.	--		
WT-2 & 3	0.561	N.A.	--		
FT & CI	0.549	0.349			
Sub-Total	2.531	0.349	13.8		
SO_2					
WT-1	2.410	N.A.	--	--	--
WT-2 & 3	3.239	N.A.	--	--	--
FT & CI	1.983	1.452		459.0	428.4
Sub-Total	7.632	1.452	19.0	459.0	428.4
NO_x					
WT-1	0.620	N.A.	--		
WT-2 & 3	0.885	N.A.	--		
FT & CI	0.574	0.057			
Sub-Total	2.079	0.057	2.7		
TOTALS	12.242	1.852		459.0	428.4

---

*Costs are placed in table opposite SO_2 control, but are shared by all pollutants.

N.A. = Not applicable.

TABLE 6-4

FUEL SWITCHING STRATEGY ON ALL INTERMEDIATE BOILERS

	Emissions (10^6 tons/year) 1975 Trend	Reduction	Individual Pollutant Percent Reduction	Cost* (10^6 \$) Capital	Annual Operating
Particulates					
WT-1	1.421	1.287			
WT-2 & 3	0.561	0.496			
FT & CI	0.549	0.349			
Sub-Total	2.531	2.132	84.3		
SO_2					
WT-1	2.410	2.023		279.6	378.3
WT-2 & 3	3.239	2.876		208.4	338.5
FT & CI	1.983	1.452		459.0	428.4
Sub-Total	7.632	6.351	83.3	897.0	1145.2
NO_x					
WT-1	0.620	0.133			
WT-2 & 3	0.885	0.271			
FT & CI	0.574	0.057			
Sub-Total	2.079	0.461	22.2		
TOTALS	12.242	8.944		89.70	1145.2

---

*Costs are placed in table opposite SO_2 control, but are shared by all pollutants.

N.A. = Not applicable.

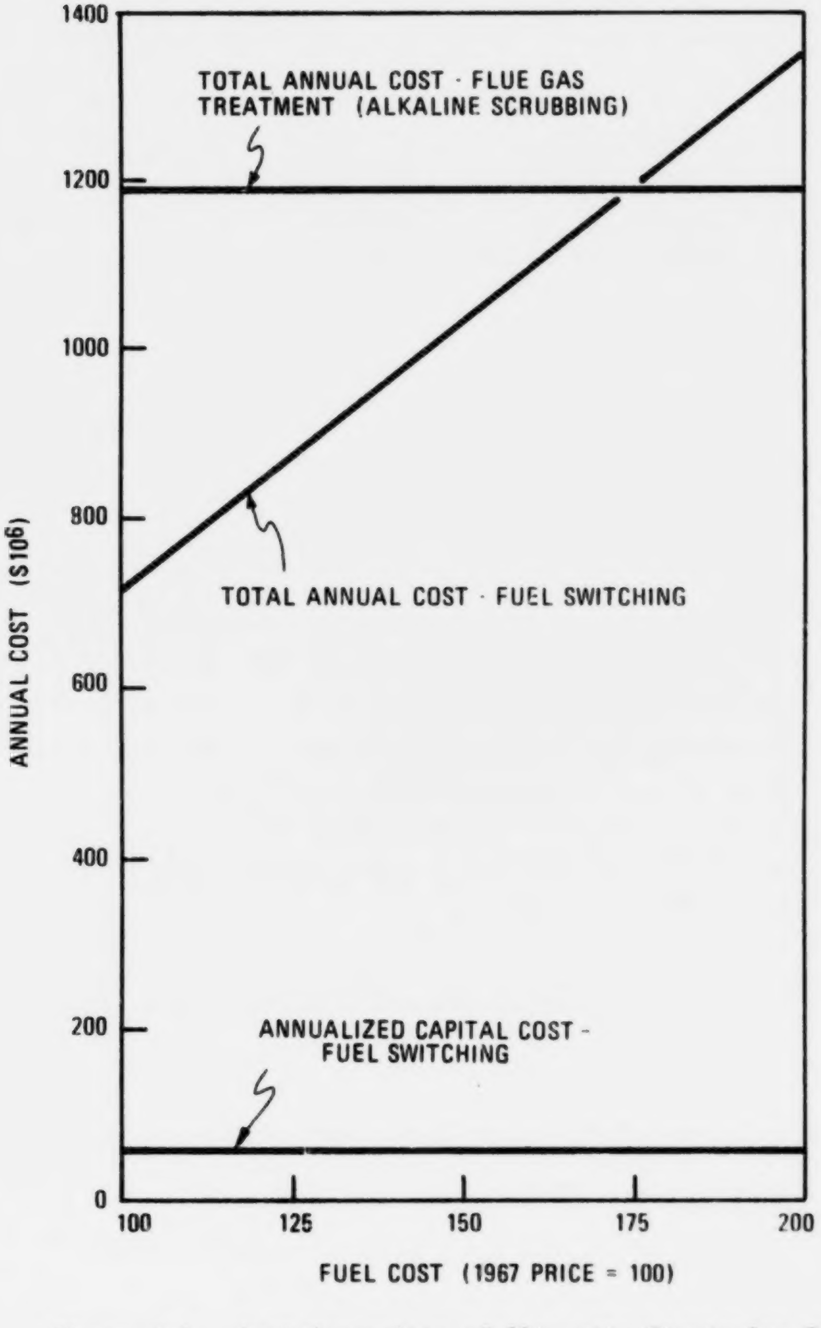


Figure 6-1. Cost Comparison of Alternate Strategies for Watertube Boilers.

higher because the capital costs of flue gas treatment are 5.75 times greater than for fuel switching, as shown in the above tables.

The same choices and economic influences are not relevant to the firetube and cast iron boilers. There, the only presently feasible alternative to fuel switching is mechanical flue gas treatment, i.e., dust collectors which, of course, afford no reduction of SO_2 or NO_x and therefore are not valid strategies for overall emissions control.

F. ECONOMIC IMPACT ON USERS

Adoption of the fuel switching strategy by all operators presently using coal or residual oil in intermediate size boilers will have an economic impact with respect to both capital costs, operating costs, as has been shown in the above tables. These figures are shown on an absolute basis, however, and it may be more meaningful to examine these costs in relation to other capital and operating costs more familiar to the users.

1. Capital Cost

The capital costs of these strategies, both in absolute and comparative terms, warrant examination in comparison with alternative -- replacement of coal-fired boilers by new units already equipped with gas/oil firing. In other words, is the cost of converting present coal fired boilers, for a fuel switching strategy, so great that complete new boiler plants warrant consideration from an economic basis?

Replacement cost for a boiler in an existing location is a very difficult determination for an average installation. Factors such as accessibility, foundation requirements, fuel supply, re-use of the existing stack, and others could be simple as with a new installation or very difficult if the existing steam plant is in the middle of a very crowded, 100-year old factory complex. The following estimates in Table 6-5 are believed to be representative or average. These are summed in Table 6-6.

TABLE 6-5

CAPITAL COST ESTIMATES FOR REPLACEMENT OF COAL FIRED EQUIPMENT

Size	Average Size in pph	New Fuel	No. of Units	\$/pph*	\$/unit**	$\$ \times 10^9$
WT-1	37,000	gas	4,134	6	221,000	.915
		gas/oil	3,782		255,000	.965
WT-2	164,000	gas	737	4	652,000	.481
		gas/oil	659		725,000	.477
WT-3	275,000	gas	306	3	830,000	.254
		gas/oil	203		940,000	.191
						3.283×10^9
FT	4,620 (140HP)	gas	11,960	4	17,500	.202
		gas/oil	7,575		27,500	.208
CI	625 (19HP)	gas	59,200	5	3,000	.178
		gas/oil	38,400		5,000	.192
						0.780×10^9

---

*Approximate unit cost per pound of steam per hour of boiler and auxiliaries, installed, including foundations, piping, and other costs.

**Above costs, but also including new fuel supply.

TABLE 6-6

ALTERNATIVE CAPITAL COST REQUIREMENTS

	Fuel Conversion	Boiler Replacement
WT-1	$229.6 x 10^6	$1,880 x 10^6
WT-2 & 3	208.4	1,403
FT & CI	459.0	780
TOTAL	$897.0 x 10^6	$4,063 x 10^6

Overall, the increase in capital requirements by replacement is some 350% greater than conversion; there is a possible advantage in total emissions by conversion in that new boilers will be slightly more efficient because of design improvements and because they would be designed rather than converted to the new fuel. However, the advantage is very slight and therefore a very poor return in terms of either capital investment or pollution levels.

2. Operating Costs

It is estimated that the units that would be switched to clean fuels have a total steam capacity of approximately 1.07 x 10^9 lbs/hr; also that they have a load factor of approximately 35%. Using this data, together with additional annual operating cost (including annualized capital cost) of $830.7 x 10^6 yields a figure of 26¢/1000 lb of steam. In view of the usual basis or allocation for industrial or commercial steam in the range of 50-70¢/1000 lb, it is seen that even this lowest cost emissions strategy adds a very substantial burden to operations. Another view indicating essentially the same impact is found in the data of Table 6-7.

It is obvious that where steam or heat plays an important part in an operation's cost structure, there will be much more resistance to this change; correspondingly, there is need for much effort to find methods that will demand less of a financial burden for adequate pollution abatement.

TABLE 6-7

FUEL SWITCHING STRATEGY OPERATING COST - FUEL ONLY

		$\$ \times 10^6$ Annually		
	Units Switched	Fuel Cost by Present Trend	Increase Due to Fuel Switching	% Increase
FT & CI	116,862	947.4	362.7	38.3%
WT-1	7,918	794.1	345.5	43.5%
WT-2 & 3	1,906	695.2	308.7	44.4%

G. SUPPLEMENTARY STRATEGIES

Because only the fuel switching and the flue gas treatment strategies are capable of effective across-the-board emissions control, only these two warranted final consideration, with the decision in favor of the former, as outlined above.

However, control need not be restricted to this action. A review of the general field of combustion design indicates that more can be done. First of all, neither of the primary strategy routes appears capable of providing much beyond 20% abatement of NO_x emissions; secondly, the individual strategies of combustion design are economically attractive with respect to both capital and operating costs. Fuel additives, low excess combustion, and flue gas recirculation all appear to have value as supplemental approaches. Inadequate dependable development has been carried out and reported in this area and results are therefore less firmly based than for fuel switching and flue gas treatment.

These strategies are somewhat restricted in their applicability, as follows:

(1) to reduce particulates from oil combustion
(2) to reduce NO_x from oil or gas combustion

They are, therefore, especially appropriate as "add-on" strategies after fuel switching, when virtually all coal firing will have been converted to gas or oil. Furthermore, they appear to have greater potential for reducing NO_x than any other known method.

1. Additives

Only fuel oil additives were considered as a control for particulate emissions from residual and/or distillate fuel oils. Also, those additives used for SO_x control from coal firing or oil firing such as MgO $CaCO_3$, etc. were dealt with as part of the flue gas treatment strategies.

Although not yet firmly established, the assumption has been made that "up to" 50% reduction of particulates from oil combustion is possible. It is within reason to use a 50% reduction figure for 1975 projections, if a program toward this goal is seriously undertaken. Space and capital cost requirements are minimized inasmuch as only drum storage and metering pumps are required for this technique. It may be practical for the fuel supplier or the refinery to carry out the necessary blending. Operating cost, like effectiveness, is not well documented. The estimates herein are based on review of manufacturers' claims and available literature.

2. Combustion Modification

Low excess air firing (LEA) and flue gas recirculation (FGR) were examined. These methods have been reputably, though not widely, demonstrated to be effective, principally on large utility boilers. It has been stated that these results are transferable, with similar performance, to virtually all sizes of boilers [6-1]. It was assumed that intermediate-size boilers, with LEA or FGR would achieve a reduction of 33% in NO_x emissions or a 50% reduction using both techniques together.

These strategies, as with additives, are not expensive, on a unit basis, with respect to capital cost and, with LEA at least, may actually result in net operating cost savings due to increased boiler efficiency.

It is possible that additives and LEA/FGR may complement each other, in a synergistic fashion, in the combustion process, helping to meet potential reduction of particulate and NO_x emissions.

3. Cost/Effectiveness of Program

Implementation of the combustion design program covering additives, LEA and FGR becomes very large in scope because it includes not only that equipment which has switched to gas and oil but also the vastly larger population of equipment already burning these cleaner fuels. The effect of applying these strategies is shown in Table 6-8. Thus, it is seen that these supplemental strategies are beneficial from a reduction potential basis of only incremental value for particulates, but of decided significance for NO_x. However, the capital cost of applying low excess air and flue gas recirculation to the firetube and cast iron segments, about 2,000,000 units, is staggering in total ($7.6 x 109). Looked at as an investment requirement for the individual boiler operator, it is not a large sum of money in itself, perhaps, but is still a very considerable "add-on" compared to the boiler plant cost itself - 60 to 100% additional for cast iron boilers and 10 to 15% for watertube boilers (see Tables 5-15 and 6-5).

It does not appear efficient by the cost/effectiveness characteristics to apply the combustion modification strategy on the firetube and cast iron segments of intermediate-size boilers. This reduces overall reduction of NO_x to a significant degree, but the economic burden on the smaller boiler operators cannot be ignored.

H. MAXIMUM REDUCTION-REASONABLE COST TOTAL PROGRAM

Under maximum pressure or incentive to bring emissions to the lowest practical level over the short-term, say 1975, it is conceivable that all of the individual strategies outlined above could be implemented. Except for the elimination of the combustion modification strategy on firetube and cast iron units, the combination is an all-encompassing state-of-the-art program comprised of the following strategies:

TABLE 6-8

COMBUSTION DESIGN STRATEGY ON ALL INTERMEDIATE BOILERS

	Emissions (10^6 tons/year)		Individual Pollutant	National Total Cost ($\$ \times 10^6$)	
	1975 Trend	Reduction	Percent Reduction	Capital	Annual Operating
Particulates					
WT-1	1.421	0.057		0	6.8
WT-2&3	0.561	0.023		0-	4.1
FT & CI	0.549	0.094		0	8.6
Sub-Total	2.531	0.174	6.9	0	19.5
SO_2					
Sub-Total	7.632	N.A.	--	--	--
NO_x					
WT-1	0.620	0.268		226.0	22.6
WT-2 & 3	0.885	0.350		117.1	0
FT & CI	0.574	0.341		7650.0	765.0
Sub-Total	2.079	0.959	46.1	7993.1	787.6
TOTALS	12.242	1.133		7993.1	807.1

(1) Fuel switching from coal to low sulfur residual oil, distillate oil or gas according to size and region for reduction of particulates and SO_2, especially, and some NO_x.

(2) Fuel additives for all oil firing in all sizes for incremental particulate reduction.

(3) Combustion modification by LEA and FGR in all watertube sizes for significant NO_x reduction.

The summary results of this maximum program are set forth in Table 6-9.

A graphic presentation of these same results is shown in Figure 6-2. This diagram displays annual operating cost vs emissions reduction with a "vector" for each of the strategies suggested above. The slope of each line indicates the cost/effectiveness value of each strategy with the lower slopes being those that reduce the most per unit of cost. Readily seen here are: (1) fuel switching will be the most effective, albeit at great cost; (2) the supplementary strategies neither cost much nor have substantial overall effect, and (3) the cost of implementation of combustion design for firetube and cast iron boilers are completely inconsistent with its gains.

Closer examination of strategies reveals that fuel switching on watertube boilers is definitely more rewarding, on a cost/effective basis, than on firetube and cast iron equipment. This is attributable to higher costs for the small boilers due to greater capital cost per unit size and the consumption of more expensive distillate fuel. This refinement of the fuel switching strategy is indicated in Figure 6-2.

I. INFLUENCE OF FUEL SUPPLY

Fuel switching appears to be the strategy that is most cost/effective for intermediate-size boilers. This conclusion was reached, as noted, without consideration of interfuel competition among the major users. The question remains as to how practical will this solution be when consideration is given to:

TABLE 6-9

OVERALL COMPOSITE PROGRAM FOR ALL INTERMEDIATE BOILERS

Pollutant and Boiler Size	1975 "trend" emissions 10^6 tons/year	10^6 tons/year Emissions Reduction		Total Reduction %	10^6 Capital Cost	10^6/year* Operating Cost
		Fuel Switch	Supplemental			
Particulates						
WT-1		1.287	0.057		0	6.8
WT-2 & 3		0.496	0.023		0	4.1
FT & CI		0.349	0.094		0	8.6
Sub-Totals	2.531	2.132	0.174	91.2	0	19.5
SO_2						
WT-1		2.023	--		279.6	378.3
WT-2 & 3		2.876	--		208.4	338.5
FT & CI		1.452	--		459.0	428.4
Sub-Totals	7.632	6.351	--	83.4	897.0	1145.2
NO_x						
WT-1		0.133	0.268		226.0	22.6
WT-2 & 3		0.271	0.350		117.1	0
FT & CI		0.057	0		0	0
Sub-Totals	2.079	0.461	0.618	51.9	343.1	22.6
TOTALS	12.242	9.736			1240.1	1187.3

*Fuel switching cost shown opposite SO_2 but are shared by all pollutants.

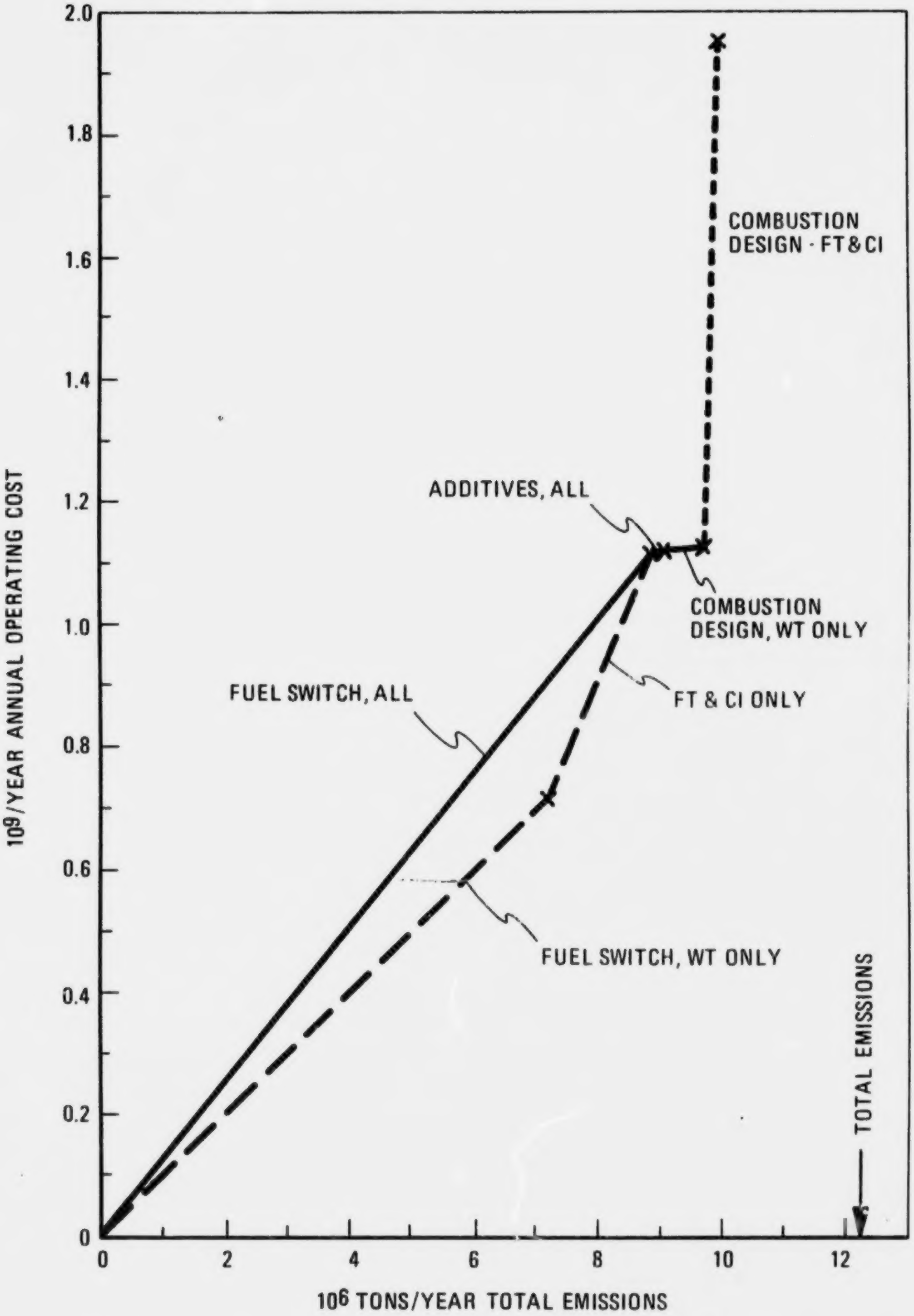


Figure 6-2. Cost Effectiveness of Strategies for Combined Emission Control.

(1) the short supply of so-called "clean" fuels

(2) the increase in fuel prices that may be expected in the future

1. Supply Factors

Examining the projected fuel use for 1975 with fuel switching, the demand for gas and residual oil by intermediate boilers is noted in Table 6-10. The total supply in 1967 is also noted in the table. It appears that in an absolute sense, there will be an adequate supply to meet the demand, particularly considering generally increasing supply trends over the past several decades. It is difficult, however, to determine whether the projected demand for oil and gas will be available for the intermediate-size equipment. It will be a matter of national fuel policy (or lack thereof) how the oil and gas supply will be split among the large utility users, the residential users, and the intermediate boiler group.

TABLE 6-10

FUEL DEMAND WITH SWITCHING - 1975
Intermediate Boilers Only

Fuel	1975 Demand With Switching	1975 Trend*	1967 Supply
Distillate Oil (10^6 barrels)	670	928	829 [6-2]
Residual Oil (10^6 barrels)	918	896	690 [6-2]
Natural Gas (10^{12} cubic ft)	16.9	27.0	18.2 [6-3]

---

*1975 trend is based on 1967 reported figures assuming continued growth through 1975, at the average historical rate from 1963 to 1967.

Large increases in the supply, sufficient to accommodate all users are not likely. Both oil and natural gas are relatively scarce [6-4, 6-5,6-6], and the allocation of these fuels will involve a careful weighing of the alternatives available to the various users.

Coal, on the other hand, appears plentiful, even for many decades as noted by Resources for the Future [6-7]; "The United States has more than enough coal to meet any increased demand that might result if a shift in price relationship should cause some consumers to shift from oil and gas to coal." Other non-economic pressures (such as environmental constraints) would have the same effect as price changes. Further, even the most extreme demand levels for coal should be met at no significant production cost increase [6-4].

Great pressures through regulatory actions now tend to channel these fuels away from the intermediate user. The FPC appears to be promoting an increase in use of gas by utilities as a means to abate pollution [6-8], although it is noted and emphasized that natural gas cannot possibly replace all the uses of coal and oil in the country as a preventative measure against air pollution [6-9]. Others suggest oil as the solution to power plant air pollution, but no real general fuel policy has been offered [6-10].

The situation for the utility industry with respect to fuel use is summarized below:

Fuel	Positive Points	Negative Points	Needs
coal	large supply, price relatively stable	present sources high in sulfur	commercially acceptable flue gas treatment process
gas	clean	scarce, price going up, only short-term alternative	coal-gasification LNG
oil	relatively clean especially if low sulfur	relatively scarce, price going up, only short-term alternative	
nuclear	clean, available	time lag and price higher than expected, limited Uranium supply	commercially acceptable systems; advanced reactors

If we examine the major options available to all users, it would appear that the utilities have the most flexible position. To reduce pressure on the oil and gas supply from the residential sector, either conversion to electric heat or switching back to coal can be utilized. The latter is quite obviously, very unsatisfactory. The former approach shifts the problem even more toward the utilities and may be quite attractive when the entire national energy system is examined from a pollution control effectiveness point of view.

Utilities can apply flue gas treatment control processes more economically and more practically from an operating point of view than any of the other groups of stationary sources. Rescinding present sulfur limits now restricting coal burning in certain areas in conjunction with use of flue gas treatment would restore the economies available in burning local coal supplies. Thus, from an optimum fuel utilization point of view, the solution for the large utility plants appears to be the use of coal coupled with good emission controls, or, even further, to switch from fossil fuel combustion to nuclear energy, or a combination of the two. Several emission control processes are already being offered commercially. Particulate control equipment is now generally acceptable as far as efficiency and cost are concerned.

Negative pressures now inhibit that solution. Methods for limiting sulfur oxides emissions are being tested at various locations using large boilers, but "none of the proposed methods have yet been demonstrated to be adequate in full-scale, full load applications", according to the FPC [6-11]. No satisfactory means of reducing nitrogen oxides has been demonstrated. Nuclear power plants have similarly encountered various delays in construction scheduling, along with substantial increases in construction costs. This has caused several utilities to meet the power requirements by returning to fossil-fired plants where nuclear plants would have been installed if they had met the original schedules [6-12].

This discussion, although brief and not intended to be a comprehensive examination of fuel supply-demand relationships or national fuel policy development, nevertheless, points to the need to examine these subjects very carefully in further evaluating controls for intermediate boilers. It appears likely that the unrestrained trends in fuel use presently observed and the growing pressure on supply by utilities, if left entirely alone, will not permit widespread utilization of fuel switching for intermediate-size boilers.

2. Fuel Prices

It is, at present, very difficult to say much about fuel prices. Prices depend on supply and demand, and when supply is short and demand for cleaner fuels is high, prices rise if the economy is a competitive one. Because of the non-existence of a fuel consumption policy for stationary sources, the demand for oil and gas has been totally unchanneled. The political situation in the Mideast and until recently in Nigeria, as well as the new demands by South American governments as to their share of the petroleum profits, have made supply not only short but insecure as well. Compounding the problem, domestic import restrictions and price control limit the supply even further. In spite of the above it is felt that fuel switching will remain the most feasible solution for intermediate boilers in the future. If large utility plants are induced by a positive fuel policy to burn coal in combination with flue gas control equipment or to switch to nuclear plants, the necessary oil and gas will become available for the suggested strategies for intermediate boilers.

Coal prices are not expected to go up significantly, reflecting only cost changes at the mine. There continuing advances in cost cutting mechanization, increased output per man-day, and the likelihood that coal wages will not increase with greater speed than wages generally, all suggest relative stability of the costs for coal [6-7]. Substantial increases in the prices of residual oil and natural gas are more probable, but not of such magnitudes as to offset the cost difference between fuel switching and the installation of satisfactory control equipment by 1975. This would more or less involve almost a doubling of oil and gas prices in the period between 1967 and 1975 in all regions and for most commercial and industrial users.

REFERENCES TO SECTION VI

6-1. Bartok, et al., "Systems Study of NO_x Control Methods for Stationary Sources," Esso R&D Co. (NAPCA Contract PH 22-68-55), November 1969.

6-2. Mineral Industry Surveys, Annual "Shipments of Fuel Oil and Kerosene," U.S. Bureau of Mines, 1967.

6-3. Minerals Yearbook 1967, Volumes I-II, U.S. Bureau of Mines, 1967.

6-4. Cambel, A. B., Energy R&D and National Progress, prepared for the Interdepartmental Energy Study by the Energy Study Group under the direction of Ali Bulent Cambel, U.S. Government Printing Office, 1964.

6-5. Moore, J. C., United States Petroleum through 1980, U.S. Dept. of the Interior, July 1968.

6-6. A Staff Report on Natural Gas Supply and Demand, Bureau of Natural Gas, September 1969.

6-7. Landsberg, H. H., Natural Resources for U.S. Growth, The John Hopkins Press, Baltimore, 1964.

6-8. Rein, B. D., "Obtaining Boiler Fuel Gas to Reduce Air Pollution," Law and Contemporary Problems, 1968.

6-9. Bagge, C. E., "The Electric Power Industry in Crisis and Transition," Proceedings of the American Power Conference, 1970.

6-10. Poole, A. J., "Application of Gas and Oil Burners to Coal-Fired Boilers," Proceedings of the American Power Conference, 1969.

6-11. The 1970 National Power Survey, Part III, Federal Power Commission, U.S. Government Printing Office, 1970.

6-12. The Nuclear Industry - 1969, U.S. Atomic Energy Commission, U.S. Government Printing Office, 1969.

VII. RECOMMENDATIONS

Examination of the results of the development of the emission estimates and projections, and of the analysis of control strategies, point to three principal sets of recommendations:

(1) Improvements on the present study
(2) Implementation of fuel switching
(3) Development of alternative approaches

A. IMPROVEMENTS OF THE PRESENT STUDY

The first set reflects uncertainties and limitations resulting from assumptions, idealizations, and imperfect data inputs inherent in the analytic procedures employed in the study. The significance of the intermediate-size equipment depends on its contribution to pollutant levels both in an absolute sense and also relative to other sources. Priorities depend on the latter factor, whereas ultimate need for action depends on the former. Comparison, as has been carried out herein, on an annual total emission basis (tons per year), as stated earlier, does not account for differences in contributions to ground-level concentration due to seasonal factors, source location, and stack height. Examination of the influence of these factors would add substantially to the significance of the results.

Anticipating that strategy evaluation appears more meaningful on the basis of combined effects on all three pollutants, it would be valuable to develop a parallel means to combine the emissions into a single quantity using some weighting factors to account for permissible levels of exposure.

Other improvements are more direct. The study should be updated and checked against actual future developments. More fine structure should be introduced. Seasonal variations in load factor, user load practices, better emission factors reflecting age, conditions and specific type of equipment would provide more precision in the estimates. Emission factors for small-size equipment are not as well characterized as those for large-scale units. Transients are more important as is the operating condition of the equipment.

In addition to these topics, there are several areas in the analysis of control strategies that would benefit from additional study. Similar to the need to develop suitable combined measures of pollutant emissions, it would be useful to develop combined measures of effectiveness. The procedure used herein merely added percentage reduction of each pollutant without any weighting. A uniform annualized factor for capital costs (discount rate) was employed for all users; more correctly, the rate will vary according to the size of installations and user. A re-examination of the relative costs, using discount rates varying according to user should be made. It is not expected that such an analysis will alter the margin for conclusions of the study, but will more clearly indicate the absolute and relative cost of any approach.

The fuel switching analysis depends on several key assumptions regarding fuel price and availability. Re-examination considering supply price forecasts should be made. The effects of various degrees of substitution by nuclear (or other energy sources) should be made concomitantly.

No major consideration of alternative means to provide process steam or space heating was introduced. Substitution of utility-generated pipeline steam or electric heat for intramural steam raising is an alternative to fuel switching that merits evaluation. The control onus is entirely shifted to the large central utility units. Overall thermal efficiency can be increased, in theory, reducing fuel consumption.

Only throwaway or centralized-regenerative processes were considered as feasible control approaches. Throwaway processes were thoroughly examined in the study. Centralized-regenerative schemes were not analyzed in detail. There are potential advantages to be gained; elimination of large water disposal problems and economic recovery of marketable by-products. The feasibility of scaling regenerative processes, the cost and feasibility of transporting absorbents between the recovery plant and individual boilers, the design of simple, unattended, small-scale sorbers all should be examined in order to fully evaluate this approach.

Finally, the impact of the new proposed national emission standards should be examined. In this, and other systems studies, selection of favored strategies for immediate implementation or for research and development programs was based largely on relative cost-effectiveness. The new standards add a further constraint in that the controls must achieve an absolute maximum in emission levels, and cost-effectiveness may no longer be the proper yardstick in selecting effective abatement control.

In summary, the following topics should be examined in order to improve on and enlarge the significance of the present study.

Improvements on Present Study

- Re-examine emission levels considering
  - seasonal fluctuations
  - stack height
  - source location
- Refine regional structure
- Examine sensitivity of results to assumptions and error in inputs
- Update inventory and emission estimates
- Use more realistic operating factors
  - load factor as function of user
  - effect of transients on emission factor
  - effects of age, operator competence, equipment condition
- Refine fuel switching analysis
  - supply/demand limitations
  - price projections
  - substitution of nuclear power
- Use discount rate (annualizing factor) depending on user
- Develop better combined measures of effectiveness
- Examine alternative means for providing space heating and process steam for intermediate-size users

  - electric heat
  - for core-city demand, supply from utility, incinerator or centralized low-pressure steam plant
- Examine regional, centralized flue gas treatment
  - logistics
  - costs
  - process selection
- Examine impact of absolute emission standards

B. IMPLEMENTATION OF FUEL SWITCHING

Fuel switching was shown to be the preferred control strategy for intermediate boilers so long as fuel prices do not increase beyond the crossover point at which combined flue gas treatment becomes competitive. Examining recent trends in price, particularly for low sulfur residual oil, now in high demand, it might appear that that point would be reached in the near future. Because fuel switching has many attractive features other than low annual operating costs -- such as low capital cost, minimum operator attendance and retraining, low maintenance -- it is important to seek means to maintain the price of fuel and the adequacy of supply at levels where this strategy remains effective.

One such approach is the development and implementation of a national fuel or energy policy which allocates fuels among major users according to some environmental and economic constraints. Noting first the difficulties and problems in formulating and putting into practice any such policy, it is nevertheless recommended that a careful study of fuel allocation policies be made. Restricting utility stations to coal or high sulfur residual oil (even in gas-rich regions, perhaps) would assure an adequate supply of clean fuels for intermediate and small boilers through 1990 and beyond. The utilities are better equipped to finance and operate large-scale flue gas treatments (recovery systems). Incremental capital needs for pollution control in new large-scale installations are considerably less than for intermediate-size units.

An alternative to a fuel allocation policy is the development of processes to convert the dirty fuels, coal or high-sulfur residual oil, into clean fuels. Processes for oil desulfurization now exist and are being implemented to increase the supply of low sulfur oils. Petroleum supplies are limited, and an alternative is needed to provide adequate clean fuel in anticipation of the time when petroleum supply cannot keep up with growing demand. Coal is a much more plentiful energy resource. Processes for conversion of coal to gas are now and have been under development for some time. The historic impetus for such process development has been primarily economic, without environmental considerations. Now the environmental factors accentuate even further the desirability of rapid development and commercialization of such processes. As such, support of coal conversion processes R&D, and coordination with agencies now responsible for such programs is recommended. Further planning studies should be made to establish priorities and funding levels.

Associated with fuel switching as a broad strategy are two technological means to complement that strategy and achieve further reduction in pollutant levels. Employment of combustion additives can, in principle, reduce the total pollutant burden on top of the gains accomplished by switching above. Under certain conditions, combustion additives can reduce particulate and sulfur oxides. Not enough is understood about the theory and operating characteristics of additive performance. Further study of the theory of additives, improvements on the present art, demonstration of use, and development of user guides should be carried out.

Likewise, combustion modification by the several approaches examined and detailed above, should be studied for application to intermediate-size boilers as it offers a potential means to reduce NO_x emissions superposed on the basic reduction from fuel switching. This approach can be applied to intermediate-size equipment without substantial capital requirements and can lead to reductions in operating costs through increase in boiler efficiency. A program in this area should include (1) studies of combustion including development of models, (2) demonstration of intermediate-size units employing low excess air, flue gas recirculation, or two-stage combustion, (3) development of burners for low excess air oil burning, (4) development of better combustion controls, (5) studies of effects of operating parameters on emissions and (6) studies of relationship of fuel nitrogen to nitrogen oxide emission levels.

The last topic is of considerable interest currently as there is evidence that fuel nitrogen follows a different route in the formation of nitric oxide than does atmospheric oxygen. If so, then the methods being developed for reduction of nitric oxide formation due to atmospheric fixation in the flame may not be effective.

It is extremely difficult to assign priorities to the several possible technological means to control emissions from intermediate boilers. If the problem is examined from the point of view that the method must offer reasonable potential control of all three major pollutants simultaneously, then only fuel switching and flue gas treatment qualify, as discussed above. Whereas both these approaches appear capable of providing adequate and effective control of particulates and sulfur oxide, neither is expected to provide substantial reduction of nitrogen oxide.

If, then, it becomes necessary to reduce nitrogen oxide emissions beyond that obtained by fuel switching or flue gas treatment, some additional means will be required. Combustion modification appears to be the best choice. It is the only approach by which reductions greater than about 10 to 20% have been achieved to date.

Existing coal-burning watertube boilers, as a class, represent a large fraction of the sources of nitrogen oxides from intermediate-size equipment. The application of either low excess air or flue gas recirculation control techniques to coal-fired units, particularly stokers, has yet to be demonstrated to be effective in reducing nitrogen oxides, unlike the case for fluid fuels where the approach is most promising. In view of the characteristics of the sources, however, this approach should be stressed as a means to obtain near-term abatement in existing systems. New coal-burning systems are projected to account for an increasingly small percent of new boilers. Some local regulations now essentially prohibit coal-burning (e.g., New Jersey State Regulations), which will probably accentuate the trends based herein on fuel economics. Thus, research and development on new systems should stress oil- and gas-burning units, for which the approach appears promising both on technical grounds and also in terms of the increasing use of fluid fuels.

The cost of applying low excess air or flue gas recirculation to existing small cast iron and firetube boilers is high. New systems incorporating either of these features and costing only incrementally more than existing designs should, in theory, be possible to develop. This suggests that priorities for research on smaller units should be given to new system development rather than toward means to retrofit existing boilers.

Before summarizing, it is noted that the programs leading to the application of combustion additives offer promise only in conjunction with and in addition to fuel switching. The small potential reduction in pollutant levels by that approach applied independently does not suggest a high priority for extensive research and development at present.

In summary, the following topics should be examined as part of a program to implement fuel switching as a control means for intermediate-size boilers.

Implementation of Fuel Switching

- Fuel availability assurance
  - develop national fuel use policy
  - develop coal conversion technology
- Combustion additives R&D
  - theoretical studies
  - pilot and full-scale testing
- Combustion modification R&D
  - combustion modeling
  - effects of fuel nitrogen - limitation to modification approaches
  - demonstration of intermediate-size applications of LEA, FGR, TSC
  - combustion control improvement
  - reduction of emissions by controlling time, temperature, excess air, fuel flow cycles
  - burners for LEA oil burning

C. ALTERNATIVE APPROACHES

It was noted that fuel switching is the better strategy up to some point when fuel costs become so high that the economics support flue gas treatment as a more effective alternative. Although there appears to be approaches (above) to lessen the probability of this occurrence, it appears desirable to support a program in flue gas treatment as a backup measure. Both economic and practical factors show that such processes should be capable of simultaneously removing most (above 80%) of the particulates and sulfur oxides, and at least 20% of the nitric oxides.

Alkaline scrubbing schemes have potential to achieve that overall level of performance, but have not been commercially developed for application to intermediate-size systems. It is recommended that a program be undertaken to include:

(1) Study of the fundamentals of scrubbing thermodynamics and kinetics

(2) Determination and optimization of the combined effectiveness

(3) Design and demonstration of unattended systems for intermediate-size boilers as small as the firetube category, if not the cast iron units.

It was pointed out that regenerative/recovery schemes appear practical only in a centralized basis. Therefore, the program should also include studies to develop such processes, separating the flue gas treatment stages from sorbent regeneration.

Solid sorbent systems have been developed for large-scale systems. Most are based on complex moving or fluidized bed contactors and regenerators, which operations are poorly suited for intermediate-size systems. Fixed bed, replaceable sorbent units show some promise in application to smaller units. There is very little design or theoretical data on the performance or cost of such systems. It is recommended that a program examining potential solid sorbents and recovery systems based on them be undertaken.

New combustion processes, in which emissions are reduced by changes in the combustion regime or are removed in situ bear promise as still another alternative to fuel switching. Fluid bed combustion is an example of such a process. While presently being considered as a potential means to control emissions from large units, its potential application to intermediate-size systems has not been thoroughly explored. All available data have been gathered on experimental units of intermediate size so that perhaps unintentional demonstration of basic feasibility has already been provided. It is recommended that examination of the applicability of this process specifically to intermediate-size equipment be carried out.

Summarizing the alternatives to fuel switching, it is recommended that the following topics be examined:

Alternative Approaches

- Develop intermediate-scale alkaline scrubbing processes
  - laboratory scale research - thermodynamics kinetics
  - combined removal - SO_2, NO_x, particulates
  - optimize combined effectiveness
  - centralized regenerative process development
  - design and demonstration of unattended systems
- Solid sorbents for flue gas treatment
- New combustion processes
  - fluid bed combustion
  - compact or miniature burners

APPENDIX A

METHODOLOGY FOR GENERATING EMISSION ESTIMATES

The methods used in gathering, selecting and manipulating equipment, fuel and operational factor data are discussed in this section. The generation of the inventory was accomplished with a computer-based procedure (STRAT) developed specifically for this application. The operational characteristics of STRAT are shown schematically in Figure A-1. The overall program was designed with a great degree of generality and flexibility to meet the changing requirements of this project and others in the future.

The main program primarily provides logic flow, input-output control, and selection of proper data files. The bulk of the factual data on which the inventory is structured are stored in separate subroutines or data files and are called into the main program at the appropriate steps. The discussion that follows describes the contents of each of the parts of this program and the means by which the data were obtained.

A. STRAT PROGRAM

The main-line STRAT program consists of the following basic components. Note that this report covers only the inventorying phases of the project. The program has elements both for this portion and for the evaluation of control strategies that will follow. Both processes are closely coupled in the computer program which consists of the following basic components:

(1) A means for establishing and cataloging subsets of the basic source inventory file (controlled subsets) in such a way that a set of emission control techniques (controls) can be applied to each of the sources in the subset. In the STRAT program, the source inventory file is classed according to its regional location, size, age of equipment, fuel type, user group, and the firing method. Controlled subsets are established by defining ranges of classes to which the controls for a given strategy are to be applied.

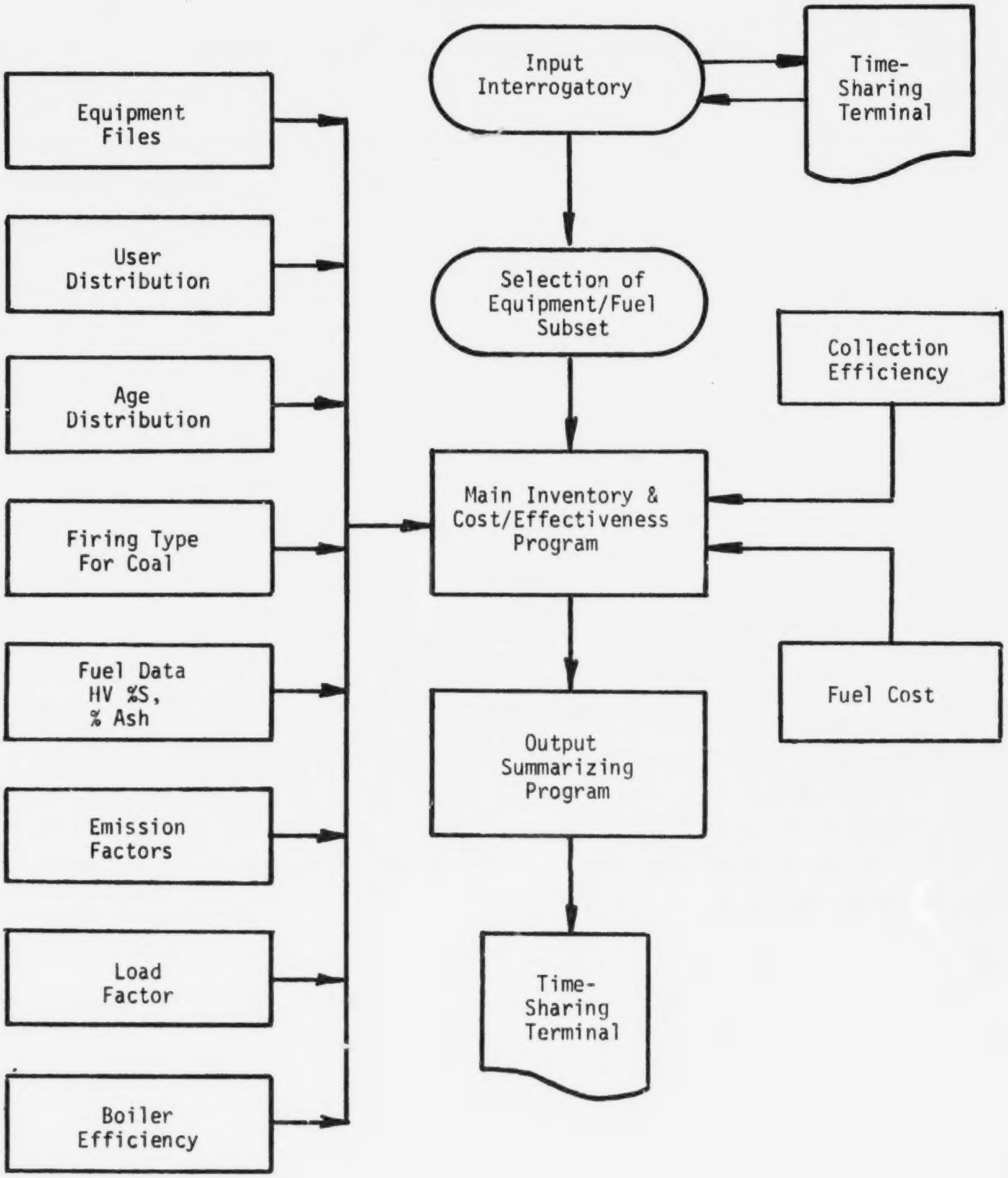

Input Interrogatory
Time-Sharing Terminal
Equipment Files
User Distribution
Selection of Equipment/Fuel Subset
Collection Efficiency
Age Distribution
Main Inventory & Cost/Effectiveness Program
Firing Type For Coal
Fuel Data HV %S, % Ash
Fuel Cost
Output Summarizing Program
Emission Factors
Load Factor
Time-Sharing Terminal
Boiler Efficiency

Figure A-1. STRAT Flow Chart.

(2) A means for modifying the source inventory file to reflect changes in emission characteristics of the controlled subsets. At present STRAT has 5 different control techniques that may be applied to the controlled subset. These are (a) to change fuel type (e.g., coal to gas), (b) to change to a cleaner grade of fuel (e.g., from high sulfur coal to low sulfur coal), (c) to change the method of firing coal furnaces (e.g., from a spreader stoker to a pulverized coal firing), (d) to add collection equipment of a given efficiency (e.g., the dry limestone injection process for SO_2 control), (e) to change operating procedures for the equipment (e.g., increase the frequency of cleaning burners of large boilers. This is reflected in increased boiler efficiency).

(3) A means for storing and processing both the modified and the unmodified source inventory files to give quantitative estimate of pollution levels and to estimate the change in pollution levels for the given strategy. Emissions are summed to estimate the total emission rate (tons per year), and the change in total emission for the region under study and for the given strategy. Other measures of pollution levels (such as ground level or peak concentration or area within a given isopleth) can be included in the model by additional programming.

(4) A means of estimating operational costs for both the modified and unmodified inventory files in order to determine the difference in operating cost for the strategy considered.

(5) A means of estimating the capital costs of the emission controls applied to the controlled subsets. This requires an estimate of, for example, the capital cost of collection equipment or the cost of converting a boiler to use a different fuel type.

(6) A means of reporting the changes in pollution levels and the operating and capital costs for a given control strategy.

(7) A means of determining the optimum control strategy for the emission inventory under study (future development). This optimization procedure may attempt to minimize, for example, the ratio of cost to reduction in the peak concentration of a pollutant or the ratio of cost to reduction in mean pollutant concentration over a given area. At present, STRAT calculates and displays only the ratio of operating costs to reduction in total emissions. Other cost-benefit ratios may be available in future versions of the program.

The calculation process begins with capacity values in pounds of steam per hour taken from the basic equipment files (Section B, below) which contain entries according to equipment size/type, region and fuel. Before computing fuel use, each entry from the input file is distributed by user and age. For units using coal, a further breakdown is available by firing types by routines within STRAT so that each step in calculating emissions is based on a single element of the very large capacity array

$$\text{Capacity} = \text{array (size/type, region, fuel, user, age, firing type)} \qquad \text{(A-1)}$$

There are seven (7) size groups, six (6) regions, four (4) fuels, four (4) age groups, four (4) users, and five (5) firing types. If all combinations were non-zero, there would be 13440 individual elements. Since only coal-fired equipment is divided by firing type, the array was, in practice, shortened to 5376 elements.

Fuel consumption and pollutant emissions are calculated according to the following equations:

$$\text{Fuel Consumption} = Q = \frac{\text{Capacity} \times 975 \times 8760 \times \text{Load Factor}}{\text{Boiler Efficiency} \times \text{Heating Value}} \qquad \text{(A-2)}$$

The factors on the right-hand side of Equation (A-2) are functions of some of the array variables in the capacity array, as described below. The numerical quantities introduced are: (1) the factor, 975, to convert from pounds of steam per hour to Btu per hour and (2) the factor, 8760, to convert the annual basis. The figure 975 was chosen as representative of the average heat content of steam relative to feed water.

There is some degree of variability in this value depending on the temperature and pressure of the steam. A single representative value appeared to be satisfactory in the emission computations.

Load factor (see Table A-5 below) is defined here as the equivalent fraction of a year that a boiler operates at rated capacity. It is implicit in this definition that the equipment is either off or on. That mode of operation is characteristic of the smaller sizes and types of boilers, residential, cast iron and firetube boilers, but not, in general, of watertube boilers. The load in large watertube boilers is often continuously varied to meet the demand for steam. For electric utility applications, the load constantly changes as demand for electric power undergoes its diurnal cycle. Data that would permit the introduction of load factors as a function of load (percent of rated capacity) were, in general, not available. Utilities keep data records of individual boiler performance, which could be used in further, more detailed studies to provide more accuracy to this element of the calculational sequence.

The boiler efficiency factor (see Table A-3 below) converts the output capacity to input fuel consumption. A single factor containing components for flue gas loss, unburnt fuel, and other losses was employed.

The combination of factors in Equation (A-2) without including heating value results in the input fuel consumption in Btu per year. This number is displayed in the printouts to facilitate comparison between units as shown below. Further division by heating value (Btu per unit of fuel) converts the Btu value into the proper unit for each fuel as:

Coal = thousand short tons
Oil = thousand barrels
Gas = million cubic feet

The emissions are then computed using the following equations:

$$\text{Annual } SO_2 \text{ Emissions} = Q \times \text{Emission Factor} \times \% \text{ Sulfur} \times (1\text{-Collector Efficiency}) \quad \text{(A-3)}$$

$$\text{Annual } NO_x \text{ Emissions} = Q \times \text{Emission Factor} \times (1\text{-Collector Efficiency}) \quad \text{(A-4)}$$

$$\text{Annual Particulate Emission} = Q \times \text{Emission Factor} \times (\% \text{ Ash}) \times (1\text{-Collector Efficiency}) \quad \text{(A-5)}$$

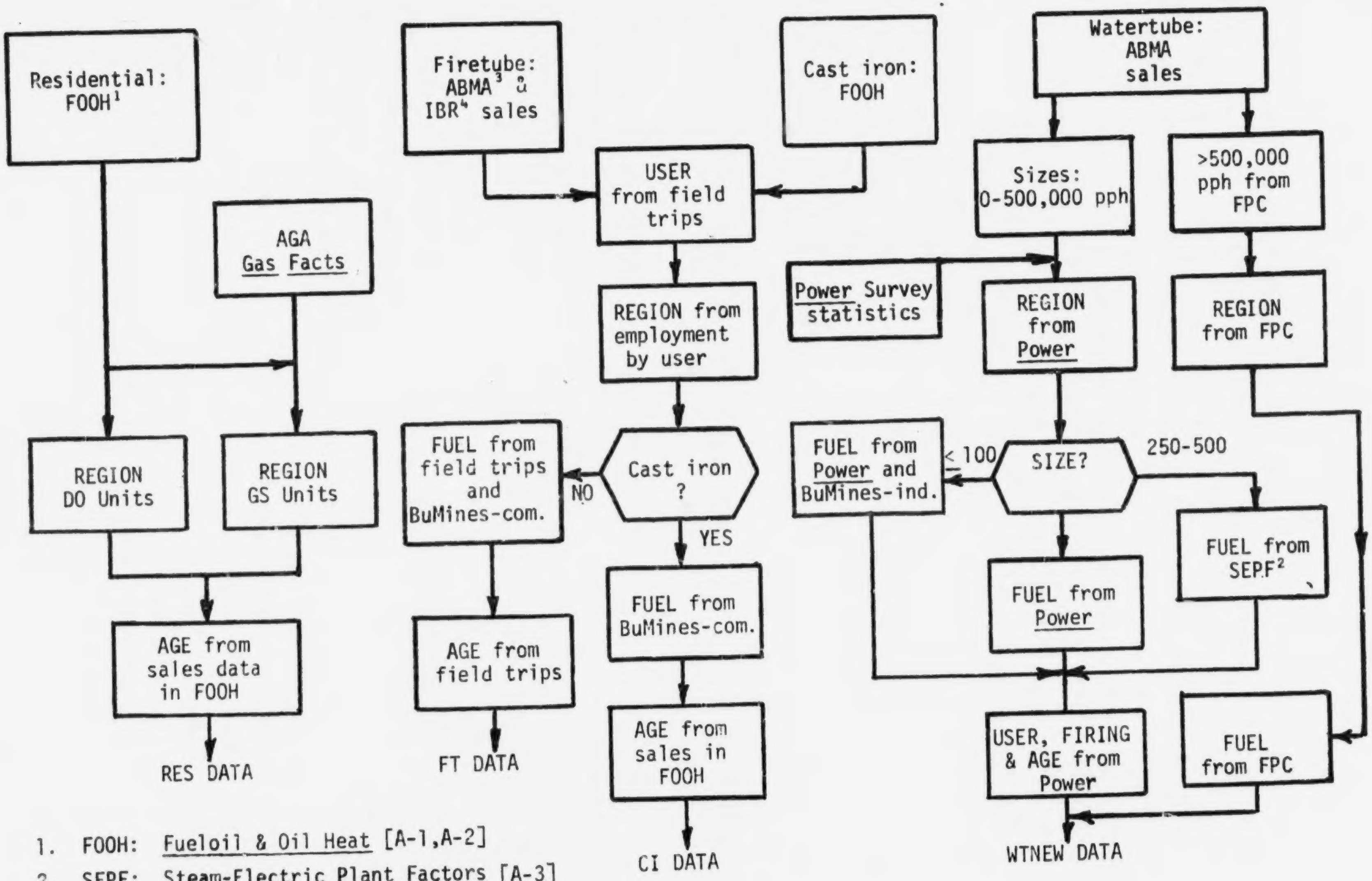
Each pollutant emission is separately computed using the proper emission factor for that species (see Table A-7 below). All emission factors for SO_2 and for coal-particulate are multiplied, respectively, by the percent of sulfur or ash in the fuel. The other emission factors are based only on the quantity of fuel consumed. The final term accounts for current abatement practices. Collector efficiency is set to zero in the computations of base levels for both SO_2 and NO_x, as essentially no control of these pollutants by flue gas treatment is presently operative or is projected for the near future. Particulate control, however, is widely applied, and a special subroutine is employed to match the proper value with the type and age of equipment.

B. SOURCES OF DATA ON BOILER CAPACITY

The factors entering into the capacity inventory can be separated from the emission part and are those indicated in Equation (A-1) above as size, type, region, fuel, user, age, and firing type. In developing the basic input files, some of the distribution (region and fuel) of gross capacity by type (the primary input) was carried out by hand, whereas the distribution by age, user, and firing type was made by subroutines within STRAT. The sources and order of operations on the basic capacity data are shown in Figure A-2. Each major equipment class was treated somewhat differently as described below.

1. Residential Boilers

An inventory of the number of residential oil burners in use at the end of 1967 was available in FuelOil and Oil Heat, April 1968, on


Residential: FOOH[1]
AGA Gas Facts
REGION DO Units
REGION GS Units
AGE from sales data in FOOH
RES DATA
Firetube: ABMA[3] & IBR[4] sales
Cast iron: FOOH
USER from field trips
REGION from employment by user
Cast iron ?
NO
YES
FUEL from field trips and BuMines-com.
AGE from field trips
FT DATA
FUEL from BuMines-com.
AGE from sales in FOOH
CI DATA
Watertube: ABMA sales
Sizes: 0-500,000 pph
>500,000 pph from FPC
Power Survey statistics
REGION from Power
REGION from FPC
SIZE?
< 100
250-500
FUEL from Power and BuMines-ind.
FUEL from Power
FUEL from SEPF[2]
USER, FIRING & AGE from Power
FUEL from FPC
WTNEW DATA

1. FOOH: Fueloil & Oil Heat [A-1,A-2]
2. SEPF: Steam-Electric Plant Factors [A-3]
3. ABMA: American Boiler Manufacturers Association [A-4,A-5]
4. IBR: The Inst. of Boiler & Radiator Mfrs. [A-6,A-7]

Figure A-2. Summary of the 1967 Boiler Inventory.

a state-by-state basis [A-1]. These data were summarized for the six regions used in this project. Using the average size of 100,000 Btu/hr (input), derived from size distributions in the same publication, regional capacity figures for residential oil burners were calculated. The total number of residential gas burners in operation by the end of 1967 was available in FuelOil and Oil Heat, January 1968 [A-2]. No regional breakdown was available from either Gas Appliance Manufacturers Association (GAMA) or the FuelOil and Oil Heat publishers. The regional breakdown was determined by using ratios derived from the number of gas customers in each region, found in the American Gas Association (AGA) publication, Gas Facts 1968 [A-8]. The results were adjusted to account for the fact that the number of residential gas customers in some of the regions included customers who are defined as commercial in this study. Coal-burning units in use in 1967 were considered to be negligible by both the GAMA and FuelOil and Oil Heat [A-9]. The age distribution for residential boilers was derived from sales data.

2. Firetube Boilers

The principal sources of capacity data for firetube boilers were collections of sales data accumulated by the Bureau of Census, Institute of Boiler and Radiator Manufacturers (IBR) and American Boiler Manufacturers Association (ABMA) [A-4,A-6,A-10]. Although no single one of these sources covered all manufacturers, the IBR estimated that approximately 75 percent of the total firetube sales were represented and reported by the combined membership of ABMA and IBR. (Thus, the inventory estimate is low by the factor 0.75.) Sales data for ABMA members were available for 1947-1968, and for IBR members only for 1965-1968. It was necessary to extrapolate these figures backwards in time to account for the firetube boilers sold previous to 1947 and which were assumed to be still in use. This assumption was based on the lifespan of these boilers derived from the data gathered during the field trips. An excellent correlation was found between sales and combined national income for primary and fabricated metals industry and for miscellaneous manufacturing. The relationship was not entirely anticipated. It would appear that firetube sales fluctuate according to the behavior of the metals industry in general. The resulting correlation was used to estimate sales data back in time only to 1943.

From data collected on field trips to a number of state and municipal boiler licensing agencies, it was found that 10 percent of the capacity of firetube boilers in use in 1967 had been installed prior to 1943 (so that the result would have to be multiplied by 1.10). Thus, to obtain the total horsepower capacity of firetube boilers in use in 1967, the following formula was used:

$$\text{Capacity} = \left[\sum_{1943}^{1967} \text{ABMA sales} + \sum_{1943}^{1967} \text{IBR sales}\right] (1.10/.75) \qquad \text{(A-6)}$$

This total was then distributed over commercial and industrial users according to the percentages obtained from the data from the field trips (56 percent commercial, 44 percent industrial). Regional distribution was made according to commercial and industrial employment figures from various U.S. Commerce Department Publications [A-11,A-12].

Fuel distribution for the firetube boilers was obtained from the field trip data, which provided only a coal-oil gas distribution. The oil burners were then further distributed over distillate and residual oil according to fuel use data for commercial establishments [A-13].

The average capacity was derived from sales data and was found to be approximately 3400 pph. The age distribution was derived from the field trip data.

3. Cast Iron

The total capacity of cast iron boilers of the commercial-industrial type in operation in 1967 was derived from sales figures for cast iron boilers [A-7]. The lifespan was obtained from field trip data, and it was found that about 10 percent of the capacity of cast iron boilers in use in 1967 had been installed prior to 1935. Furthermore, IBR data indicated that approximately 19 percent of the total capacity of cast iron boilers sold was of the commercial-industrial type, i.e., larger than 200,000 Btu/hr rating. The remainder (81%) are residential size. Thus, the total capacity of this type of cast iron boilers was determined by the following formula:

$$\text{Capacity} = \left[\sum_{1935}^{1967} \text{sales}\right](1.10)(0.19) \qquad \text{(A-7)}$$

where the factors 1.10 and 0.19 account for the capacity before 1935, and percent of sales in the intermediate-size class, respectively. The sales data used were taken from FuelOil and Oil Heat, January 1968 [A-2].

From IBR sales data, available for 1960-1969, the average capacity was calculated to be about 595 pph for this type of cast iron boilers.

The field trip data indicated that 80% of these boilers were commercial and 20% industrial. These data were insufficient as a basis to derive fuel distributions for each region for this type of equipment. Consequently, the fuel use data for commercial users (see Section IV) were applied in the form of percentages to distribute the cast iron boilers of the commercial-industrial category over the six regions. The age distribution was derived from sales figures.

4. Watertube Boilers

An important observation relative to this category of boilers was that the useful lifetime of watertube boilers was about 50 years, rather than the 30-year figure most often used. This observation followed a detailed inventory of all U.S. utility boilers compiled by a NAPCA task group from Federal Power Commission reporting forms. Thus, sales data going back 50 years were required to find the capacity of watertube boilers in use in 1967.

The sales data used were provided by the ABMA [A-5]. The data consisted of the total number and the total capacity sold each year, from 1949 to 1968, reported in three size categories: $\leq$100,000 pph, from 100,001 pph to 250,000 pph, and >250,000 pph. Walden extrapolated back to estimate sales for the additional years, using qualitative judgments about the earlier years.

a. $\leq$100,000 pph

The yearly average number of watertube boilers sold in this category prior to 1949 was estimated to be about 750. Graphically extrapolating average boiler size backwards, the total capacity sold between 1915 and 1948 was obtained by multiplying that size by 750 units per year. The total sales 1915-1966, adjusted to exclude exports and retired boilers represents the total capacity of watertube boilers $\leq$100,000 pph in use in 1967. A one-year lag to account for delivery time was used.

b. 100,001-250,000 pph

The yearly average number of watertube boilers sold in this group prior to 1949 was estimated to be about 110. Using the same means as above the total capacity sold between 1915-1948 was obtained. The total sales 1915-1965 adjusted to exclude exports and retired boilers represents the total capacity of watertube boilers of the size group 100,001-250,000 pph in use in 1967. A two-year offset for delivery was used.

c. >250,000 pph

Very few of these boilers were sold prior to the Second World War. The average yearly number sold in this large size group was estimated to be about 20 prior to 1949. As above, the average capacity for each year was found by graphically projecting the average size curve for this boiler category backwards in time. The total sales 1915-1964, adjusted to exclude exports, represents the total capacity of watertube boilers >250,000 pph in use in 1967. A three-year lag for delivery was used. No significant retirements were assumed for this category by 1967.

For the purpose of this study it was necessary to inventory separately boilers in the 250,000 to 500,000 pph range. Since almost all of the larger size are utility boilers, FPC data cards provided by NAPCA were scanned to identify and sum the units greater than 500,000 pph. By subtraction, the capacity in the desired range was obtained.

The totals for watertube boilers are shown in Table A-1 below. Data were collected from yearly surveys published in various issues of Power Magazine for 1940-1967 [A-14]. A total of about 7000 individual watertube boilers were recorded with information as to location within the U.S.A., type of user, capacity, firing type, fuel, etc. These data were summarized by means of a computer program to generate the statistics for the distribution of the watertube boilers over the various regions. The large sample from the Power survey was found to be representative of the total boiler population in each size category up to 500,000 pph.

Each of the three size categories were in this way distributed over the six regions. The Power survey was summarized in another format to obtain a "coal-oil-gas" fuel distribution for each region. The distillate-residual oil ratio from industrial fuel use data was used to distribute the total oil capacity for the watertube boilers less than or equal to 100,000 pph. For larger sizes, all oil was assumed to be residual. For the boilers between 250,001 and 500,000 pph, the fuel use percentages of the utilities industry in each region [A-3] were used to distribute fuel use in place of the Power survey statistics.

After allocation by regions and fuels, these three size categories were further distributed by user group and firing method according to the sample obtained from the Power survey statistics. The Power survey did not supply age data on boilers. The age distribution of the boilers in the FPC file was used for all utility watertube boilers. Data on paper industry boilers, collected in a study at that industry, were made available to us by NAPCA, and summarized by means of computer programs. The age distribution resulting from the paper industry analysis was used for all non-utility watertube boilers.

TABLE A-1

WATERTUBE BOILERS IN USE IN 1967

	Number	Capacity (10^6 pph)	Average Capacity
Less than or equal to 100,000 pph	34,357	921	26,800
Between 100,001 and 250,000 pph	4,015	658	163,900
Between 250,001 and 500,000 pph	942	259	274,900
Greater than 500,000 pph (util.)	1,001	1,186	1,184,100
Greater than 500,000 pph (ind.)*	53	62	1,184,100
TOTAL	40,421	3,148	1,833,800

---

*Industrial use of the very large boilers was estimated to be 5% of the total capacity of the largest size utility boilers. For convenience in this study, the very large (over 500,000 pph) industrial boilers were not separated from the utility boilers in the mixed files. The actual average size of industrial boilers in this size class is close to the lower limit, about 500,000 pph. The distinction would have to be introduced into any study directly examining the large size boilers.

For the watertube boilers greater than 500,000 pph, statistics obtained from the FPC data were used for all further distributions.

C. OTHER FACTORS IN THE STRAT PROGRAM

The calculation of fuel consumption and emission is based as shown above in Equations (A-3) to (A-5) on the application of several factors to the basic capacity data. The source of these factors and listing of the numbers used are contained and discussed in this section.

1. Firing Type

The firing type distribution was obtained from the Power survey and was not changed from year to year, since insufficient data were available showing changes over time for firing methods. The values used for this quantity are shown below in Table A-2.

TABLE A-2

FIRING DISTRIBUTION TABLE
(Fractions)

Size Code	PV	CY	OF	SS	UF
WT1	0.194	0.0	0.474	0.203	0.129
WT2	0.593	0.016	0.293	0.077	0.021
WT3	0.921	0.050	0.003	0.017	0.009
WT4	1.000	0.0	0.0	0.0	0.0
FT	0.0	0.0	0.0	0.0	1.000
RES	0.0	0.0	0.0	0.0	1.000
CI	0.0	0.0	0.0	0.0	1.000

where: PV = Pulverized Coal
CY = Cyclone Furnace
OF = Over-fired Stoker
SS = Spread Stoker
UF = Under-fired Stoker

2. Boiler Efficiency

Overall boiler thermal efficiency data, including losses due to incomplete combustion and wall and flue losses, were extracted from literature references [A-15] and from communication with Riley Stoker. Boiler efficiency is a function of equipment type and fuel. The same values were used for all years and are shown in Table A-3. Small improvements in efficiency are introduced in time, but no substantial breakthrough is expected judging from comments from several manufacturers. Improvements due to larger size, important in large utility boilers, does not apply to this study. Coal-fired watertube units show higher efficiencies than units using other fuels. The factor of 1.00 for the residential class (Code No. 6) is artificial. The basic capacity data derived from sales and statistical reports for this class are expressed as input, not output, ratings and, thus, the boiler efficiency was irrelevant in order to calculate the emissions resulting from these units. The actual efficiency of most residential equipment is in the 65 to 75 percent range.

3. Load Factors

The determination of emissions from installed capacity data requires, in the STRAT calculation schemes, estimates of the load factor expressed as the fraction of time the unit operates at rated capacity. Load factors are dependent on the type of service, such as space heating, process steam generation or power generation, and on the work schedule of the user.

To ascertain how much fuel is consumed over the year in residential and commercial space heating, a load factor was derived as follows:

a. For each state, ascertain the design temperature for heating load calculations and selection of heating plant. This is obtained by averaging handbook data, for example, the values for all principal cities in a state [A-16]. The design temperature will be higher than the record low temperature for an area.

TABLE A-3

BOILER EFFICIENCY TABLE

Size	Fuel	Efficiency
WT1	GS	0.70
WT1	RO	0.75
WT1	DO	0.75
WT1	CL	0.77
WT2	GS	0.76
WT2	RO	0.80
WT2	DO	0.80
WT2	CL	0.83
WT3	GS	0.81
WT3	RO	0.87
WT3	DO	0.87
WT3	CL	0.89
WT4	GS	0.81
WT4	RO	0.88
WT4	DO	0.88
WT4	CL	0.90
FT	GS	0.75
FT	RO	0.77
FT	DO	0.77
FT	CL	0.70
RES	GS	1.00
RES	RO	1.00
RES	DO	1.00
RES	CL	1.00
CI	GS	0.77
CI	RO	0.80
CI	DO	0.80
CI	CL	0.70

b. Calculate the maximum possible degree-days per year, as (365 days per year) x (65°F - Design Temperatures).

c. Determine from a handbook the actual degree-days in each state [A-16].

d. Compute the load factor to apply to the fuel consumption of equipment when operating at rated capacity as the ratio of actual to possible degree-days.

Examination of the resulting load factors in Table A-4 shows a range of 0.05 for Florida to 0.31 for Maine. As indicated by the extremes, the warm states, in general, have a low factor, i.e., the heating plants are in operation for only short periods and then very seldom at the design conditions. The reverse holds in the cold northern states. It is interesting to note that the states with the lowest design temperatures do not have the highest load factors. The regional summary values used in STRAT are shown in Table A-5. It must be emphasized that the emissions calculated by STRAT are total annual emissions, with no seasonal factors included.

Industrial usage varies widely and is difficult to characterize by a single load factor. There is, unfortunately, little data available from which factors can be derived. An overall load factor for all industrial boilers of 0.35 was selected and employed in the calculations. This value seems reasonable, particularly for the intermediate-size range. Examinations of data on boilers used in the pulp and paper industry and discussions with manufacturers and users of industrial boilers indicated that use declines with age, i.e., the newer, more efficient boilers are used more of the time than the older units. The values shown in Table A-5 were derived from a statistical analysis of the pulp and paper boiler data. The weighted average corresponds to the overall value of .35.

Utility load factor data are more widely available. The figures shown in Table A-5 were derived from FPC data and publications of the Edison Electric Institute (EEI) and National Coal Association (NCA) [A-3, A-17]. The national average load factor in 1967 was 54 percent. The load factor is a function of region, age, and size. Regional factors were

TABLE A-4

LOAD FACTOR DETERMINATION (FOR SPACE HEATING)

Region	State	City	Design Temp. (°F)	Max. Poss. Degree-Days	Actual Degree-Days	Load Factor	Regional Avg/Range
AT	MA		0	24,000	6,000	0.25	0.22 0.18-0.25
	RI		0	24,000	6,000	0.25	
	CT		0	24,000	5,900	0.25	
	NY	New York Buffalo Rochester	-5	25,500	6,400	0.25	
	NJ	Newark Trenton	0	24,000	5,400	0.22	
	PA	Philadelphia Pittsburgh	0	24,000	5,400	0.22	
	DE		0	24,000	4,700	0.20	
	MD		0	24,000	4,400	0.18	
	DC		0	24,000	4,600	0.19	
	VA	Richmond	15	18,000	3,900	0.22	
GL	WI	Milwaukee	-15	29,000	7,200	0.25	0.23 0.22-0.25
	IL	Chicago	-10	27,000	6,200	0.23	
	IN	Indianapolis Fort Wayne	-10	27,000	6,000	0.22	
	OH	(Several)	-5	25,500	5,700	0.22	
	MI	Detroit Lansing	-10	27,000	6,800	0.25	

TABLE A-4 (Cont.)

Region	State	City	Design Temp. (°F)	Max. Poss. Degree-Days	Actual Degree-Days	Load Factor	Regional Avg/Range
WS	HI						
	WA	Seattle	15	18,000	4,900	0.27	0.16 0.05-0.27
		Tacoma					
	OR	Portland	10	20,000	4,600	0.23	
	CA	Los Angeles	30	13,000	2,100	0.16	
		San Francisco					
		San Diego					
	NV		-5	25,500	6,200	0.24	
	AZ	Phoenix	20	16,500	2,100	0.13	
		Tuscon					
		Flagstaff					
	NM		0	24,000	4,300	0.18	
	TX	Dallas	15	18,000	2,000	0.11	
		Ft. Worth					
		Houston					
	LA	New Orleans	20	16,500	1,500	0.09	
		Shreveport					
	FL	Miami, Tampa	25	14,500	700	0.05	(lowest)
		Jacksonville					
CU	MN	St. Paul	-20	31,000	8,400	0.27	0.21 0.15-0.27
		Minneapolis					
	IA		-15	29,000	6,700	0.23	
	NB	Omaha	-10	27,000	6,700	0.25	
	MO		-5	25,500	4,900	0.19	
	KS		-10	27,000	5,300	0.20	
	AR		5	22,000	3,200	0.15	

TABLE A-4 (Cont.)

Region	State	City	Design Temp. (°F)	Max. Poss Degree-Days	Actual Degree-Days	Load Factor	Regional Avg/Range
CU	OK		0	24,000	3,800	0.16	
	CO		-10	27,000	5,700	0.21	
	UT		-10	27,000	6,000	0.22	
SE	WV		-10	27,000	4,500	0.17	0.15 0.11-0.20
	KY	Louisville	0	24,000	4,700	0.20	
	TN	Chatanooga Knoxville Memphis Nashville	5	22,000	3,300	0.15	
	NC	Asheville Charlotte Raleigh	10	20,000	3,400	0.17	
	SC	Charleston Columbia Greenville	10	20,000	2,300	0.12	
	GA	Augusta, Macon, Macon Savannah Rome	15	18,000	2,400	0.13	
	AL	Birmingham Mobile Montgomery	10	20,000	2,100	0.11	
	MS		10	20,000	2,200	0.11	
RN	ME		-5	25,500	7,900	0.31 (highest)	0.27 0.24-0.31

TABLE A-4 (Cont.)

Region	State	City	Design Temp. (°F)	Max. Poss. Degree-Days	Actual Degree-Days	Load Factor	Regional Avg/Range
RN	NH		-10	27,000	7,400	0.27	
	VT		-10	27,000	7,900	0.29	
	ND		-30	35,000	9,100	0.26	
	SD		-20	31,000	7,800	0.25	
	MT		-25	33,000	8,100	0.25	
	WY		-15	29,000	7,600	0.26	
	ID		0	24,000	5,800	0.24	
NATIONAL		-	-	-	-	-	0.20 0.05-0.31

TABLE A-5

LOAD FACTOR TABLE

User	Region	Age	Size	Load Factor
RES	AT			0.220
COM	AT			0.220
RES	GL			0.230
COM	GL			0.230
RES	WS			0.160
COM	WS			0.160
RES	CU			0.210
COM	CU			0.210
RES	SE			0.150
COM	SE			0.150
RES	RN			0.270
COM	RN			0.270
IND		1		0.376
IND		2		0.357
IND		3		0.346
IND		4		0.302
UTL	AT	1	WT1-3	0.411
UTL	AT	1	WT4	0.724
UTL	AT	2	WT1-3	0.391
UTL	AT	2	WT4	0.688
UTL	AT	3	WT1-3	0.379
UTL	AT	3	WT4	0.666
UTL	AT	4	WT1-3	0.330
UTL	AT	4	WT4	0.581
UTL	GL	1	WT1-3	0.422
UTL	GL	1	WT4	0.742
UTL	GL	2	WT1-3	0.401
UTL	GL	2	WT4	0.705

TABLE A-5 (Cont.)

User	Region	Age	Size	Load Factor
UTL	GL	3	WT1-3	0.388
UTL	GL	3	WT4	0.683
UTL	GL	4	WT1-3	0.339
UTL	GL	4	WT4	0.596
UTL	WS	1	WT1-3	0.329
UTL	WS	1	WT4	0.578
UTL	WS	2	WT1-3	0.312
UTL	WS	2	WT4	0.549
UTL	WS	3	WT1-3	0.302
UTL	WS	3	WT4	0.532
UTL	WS	4	WT1-3	0.264
UTL	WS	4	WT4	0.464
UTL	CU	1	WT1-3	0.356
UTL	CU	1	WT4	0.626
UTL	CU	2	WT1-3	0.338
UTL	CU	2	WT4	0.595
UTL	CU	3	WT1-3	0.328
UTL	CU	3	WT4	0.576
UTL	CU	4	WT1-3	0.286
UTL	CU	4	WT4	0.503
UTL	SE	1	WT1-3	0.432
UTL	SE	1	WT4	0.760
UTL	SE	2	WT1-3	0.411
UTL	SE	2	WT4	0.722
UTL	SE	3	WT1-3	0.393
UTL	SE	3	WT4	0.699
UTL	SE	4	WT1-3	0.347
UTL	SE	4	WT4	0.610

TABLE A-5 (Cont.)

User	Region	Age	Size	Load Factor
UTL	RN	1	WT1-3	0.383
UTL	RN	1	WT4	0.673
UTL	RN	2	WT1-3	0.363
UTL	RN	2	WT4	0.639
UTL	RN	3	WT1-3	0.352
UTL	RN	3	WT4	0.619
UTL	RN	4	WT1-3	0.307
UTL	RN	4	WT4	0.540

obtained from state-by-state electricity generation and capacity data [A-3]. The size-dependent part was derived by assuming that the very large boiler (over 500,000 pph) operated 15 percent above the average, i.e., as base-load plants. The age-dependent part was derived from a statistical analysis of the individual FPC plant data provided by NAPCA. All subfactors were weighted to maintain the overall utility load at 54 percent.

4. Fuel Characteristics

Data on heating value, percent sulfur, and percent ash for the four fuels were obtained from a variety of reference sources [A-18-A-21]. These data (shown in Table A-6) vary according to region and user. Utility coal heating value data were derived from state-by-state data [A-3] and NAPCA-FPC data.

5. Emission Factors

Emission factors used in STRAT were taken from several sources [A-22,A-23]. Factors for SO_2 and particulate are derived from the widely used data in the Compilation of Emission Factors [A-2]. The SO_2 factors for both residual and distillate oil were corrected for density to give more accurate factors on a unit volume basis. The NO_x factors for gas and oil are derived from regression curves fitting data collected by the L.A.A.P.C.D. [A-23]. Average size values for each class are used as the independent variable in the regression formula. The emission factor data shown in Table A-7 are for 1967. The gas and oil NO_x factors for the later years will be slightly larger due to an assumed increase in projected average size in the computation used to input the emission factor using the regression curve.

6. Collector Efficiency

This factor must be applied to the uncontrolled emission figures to account for current control practices. Stack gas control for SO_2 and NO_x is practically non-existent, except for a few demonstration SO_2 removal projects. No control was assumed in any of the computer

TABLE A-6

FUEL CHARACTERISTICS TABLE

Region	Fuel	User	Heating Value	Percent Sulfur	Percent Ash
AT	GS	ALL	0.10400E 10*	0.0	0.0
AT	RO	RES	0.63840E 10	1.340	0.0
AT	RO	COM	0.63840E 10	1.340	0.0
AT	RO	IND	0.63840E 10	1.340	0.0
AT	RO	UTL	0.63840E 10	2.340	0.0
AT	DO	ALL	0.58170E 10	0.220	0.0
AT	CL	RES	0.26200E 11	1.830	8.07
AT	CL	COM	0.26200E 11	1.830	8.07
AT	CL	IND	0.26200E 11	1.830	8.07
AT	CL	UTL	0.24700E 11	2.086	9.57
GL	GS	ALL	0.10400E 10	0.0	0.0
GL	RO	RES	0.63840E 10	1.520	0.0
GL	RO	COM	0.63840E 10	1.520	0.0
GL	RO	IND	0.63840E 10	1.520	0.0
GL	RO	UTL	0.63840E 10	2.520	0.0
GL	DO	ALL	0.58170E 10	0.247	0.0
GL	CL	RES	0.26200E 11	2.380	8.57
GL	CL	COM	0.26200E 11	2.380	8.57
GL	CL	IND	0.26200E 11	2.380	8.57
GL	CL	UTL	0.23160E 11	3.436	10.07
WS	GS	ALL	0.10400E 10	0.0	0.0
WS	RO	RES	0.63840E 10	1.440	0.0
WS	RO	COM	0.63840E 10	1.440	0.0
WS	RO	IND	0.63840E 10	1.440	0.0
WS	RO	UTL	0.63840E 10	2.440	0.0
WS	DO	ALL	0.58170E 10	0.263	0.0
WS	CL	RES	0.26200E 11	2.060	7.89
WS	CL	COM	0.26200E 11	2.060	7.89
WS	CL	IND	0.26200E 11	2.060	7.89
WS	CL	UTL	0.21760E 11	1.841	9.39

*Typically, 0.10400E 10 to be read as 0.10400 x 10^{10} Btu/fuel unit.

TABLE A-6 (Cont.)

Region	Fuel	User	Heating Value	Percent Sulfur	Percent Ash
CU	GS	ALL	0.10400E 10	0.0	0.0
CU	RO	RES	0.63840E 10	1.690	0.0
CU	RO	COM	0.63840E 10	1.690	0.0
CU	RO	IND	0.63840E 10	1.690	0.0
CU	RO	UTL	0.63840E 10	2.690	0.0
CU	DO	ALL	0.58170E 10	0.274	0.0
CU	CL	RES	0.26200E 11	2.480	8.86
CU	CL	COM	0.26200E 11	2.480	8.86
CU	CL	IND	0.26200E 11	2.480	8.86
CU	CL	UTL	0.22360E 11	2.823	10.36
SE	GS	ALL	0.10400E 10	0.0	0.0
SE	RO	RES	0.63840E 10	1.810	0.0
SE	RO	COM	0.63840E 10	1.810	0.0
SE	RO	IND	0.63840E 10	1.810	0.0
SE	RO	UTL	0.63840E 10	2.810	0.0
SE	DO	ALL	0.58170E 10	0.182	0.0
SE	CL	RES	0.26200E 11	1.670	7.72
SE	CL	COM	0.26200E 11	1.670	7.72
SE	CL	IND	0.26200E 11	1.670	7.72
SE	CL	UTL	0.24040E 11	2.455	9.22
RN	GS	ALL	0.10400E 10	0.0	0.0
RN	RO	RES	0.63840E 10	2.000	0.0
RN	RO	COM	0.63840E 10	2.000	0.0
RN	RO	IND	0.63840E 10	2.000	0.0
RN	RO	UTL	0.63840E 10	3.000	0.0
RN	DO	ALL	0.58170E 10	0.300	0.0
RN	CL	RES	0.24000E 11	1.210	9.14
RN	CL	COM	0.24000E 11	1.210	9.14
RN	CL	IND	0.24000E 11	1.210	9.14
RN	CL	UTL	0.19180E 11	1.222	10.64

Units for Gas = Btu/million cubic feet
Units for Oil = Btu/thousand bbl.
Units for Coal = Btu/thousand tons

TABLE A-7

EMISSION FACTOR TABLE

Pollutant	Size	Fuel	User	Firing Type	Factor*
SO2	ALL	GS	RES		0.0
SO2	ALL	GS	COM		0.0
SO2	ALL	GS	IND		0.0
SO2	ALL	GS	UTL		0.0
SO2	ALL	RO	RES		0.6594E 04**
SO2	ALL	RO	COM		0.6594E 04
SO2	ALL	RO	IND		0.6804E 04
SO2	ALL	RO	UTL		0.6804E 04
SO2	ALL	DO	RES		0.5838E 04
SO2	ALL	DO	COM		0.5838E 04
SO2	ALL	DO	IND		0.5838E 04
SO2	ALL	DO	UTL		0.5838E 04
SO2	ALL	CL	ALL	ALL	0.3800E 05
NOX	WT1	GS	RES		0.1676E 03
NOX	WT1	GS	COM		0.1676E 03
NOX	WT1	GS	IND		0.1676E 03
NOX	WT1	GS	UTL		0.1676E 03
NOX	WT1	RO	RES		0.2218E 04
NOX	WT1	RO	COM		0.2218E 04
NOX	WT1	RO	IND		0.2218E 04
NOX	WT1	RO	UTL		0.2218E 04
NOX	WT1	DO	RES		0.2017E 04
NOX	WT1	DO	COM		0.2017E 04
NOX	WT1	DO	IND		0.2071E 04
NOX	WT1	DO	UTL		0.2071E 04
NOX	ALL	CL	ALL	PV	0.2000E 05
NOX	ALL	CL	ALL	CY	0.6000E 05
NOX	ALL	CL	ALL	OF	0.1500E 05

*Unit at end of table.

**Typically, 0.6594E 04 to be read as 0.6594 x 10^4.

TABLE A-7 (Cont.)

Pollutant	Size	Fuel	User	Firing Type	Factor
NOX	ALL	CL	ALL	SS	0.1000E 05
NOX	ALL	CL	ALL	UF	0.1000E 05
NOX	WT2	GS	ALL		0.2280E 03
NOX	WT2	RO	ALL		0.3072E 04
NOX	WT2	DO	ALL		0.2794E 04
NOX	WT3	GS	ALL		0.2489E 03
NOX	WT3	RO	ALL		0.3372E 04
NOX	WT3	DO	ALL		0.3067E 04
NOX	WT4	GS	ALL		0.3191E 03
NOX	WT4	RO	ALL		0.4387E 04
NOX	WT4	DO	ALL		0.3989E 04
NOX	FT	GS	ALL		0.1180E 03
NOX	FT	RO	ALL		0.1529E 04
NOX	FT	DO	ALL		0.1391E 04
NOX	RES	GS	ALL		0.6506E 02
NOX	RES	RO	ALL		0.8144E 03
NOX	RES	DO	ALL		0.7407E 03
NOX	CI	GS	ALL		0.8772E 02
NOX	CI	RO	ALL		0.1118E 04
NOX	CI	DO	ALL		0.1016E 04
PART	WT1	GS	RES		0.1900E 02
PART	WT1	GS	COM		0.1800E 02
PART	WT1	GS	IND		0.1800E 02
PART	WT1	GS	UTL		0.1800E 02
PART	WT1	RO	ALL		0.9660E 03
PART	WT1	DO	RES		0.3360E 03
PART	WT1	DO	COM		0.3360E 03
PART	WT1	DO	IND		0.6300E 03
PART	WT1	DO	UTL		0.6300E 03
PART	WT1	CL	ALL	PV	0.1600E 05

TABLE A-7 (Cont.)

Pollutant	Size	Fuel	User	Firing Type	Factor
PART	WT1	CL	ALL	CY	0.2000E 04
PART	WT1	CL	ALL	OF	0.1300E 05
PART	WT1	CL	ALL	SS	0.5000E 04
PART	WT1	CL	ALL	UF	0.5000E 04
PART	WT2	GS	RES		0.1900E 02
PART	WT2	GS	COM		0.1800E 02
PART	WT2	GS	IND		0.1500E 02
PART	WT2	GS	UTL		0.1500E 02
PART	WT2	RO	RES		0.9660E 03
PART	WT2	RO	COM		0.9600E 03
PART	WT2	RO	IND		0.4200E 03
PART	WT2	RO	UTL		0.4200E 03
PART	WT2	DO	RES		0.3360E 03
PART	WT2	DO	COM		0.3360E 03
PART	WT2	DO	IND		0.6300E 03
PART	WT2	DO	UTL		0.6300E 03
PART	WT2	CL	ALL	PV	0.1600E 05
PART	WT2	CL	ALL	CY	0.2000E 04
PART	WT2	CL	ALL	OF	0.1300E 05
PART	WT2	CL	ALL	SS	0.5000E 04
PART	WT2	CL	ALL	UF	0.5000E 04
PART	WT3	GS	RES		0.1900E 02
PART	WT3	GS	COM		0.1800E 02
PART	WT3	GS	IND		0.1500E 02
PART	WT3	GS	UTL		0.1500E 02
PART	WT3	RO	RES		0.9660E 03
PART	WT3	RO	COM		0.9660E 03
PART	WT3	RO	IND		0.4200E 03
PART	WT3	RO	UTL		0.4200E 03
PART	WT3	DO	RES		0.3360E 03
PART	WT3	DO	COM		0.3360E 03

TABLE A-7 (Cont.)

Pollutant	Size	Fuel	User	Firing Type	Factor
PART	WT3	DO	IND		0.6300E 03
PART	WT3	DO	UTL		0.6300E 03
PART	WT3	CL	ALL	PV	0.1600E 05
PART	WT3	CL	ALL	CY	0.2000E 04
PART	WT3	CL	ALL	OF	0.1300E 05
PART	WT3	CL	ALL	SS	0.5000E 04
PART	WT3	CL	ALL	UF	0.5000E 04
PART	WT4	GS	RES		0.1900E 02
PART	WT4	GS	COM		0.1800E 02
PART	WT4	GS	IND		0.1500E 02
PART	WT4	GS	UTL		0.1500E 02
PART	WT4	RO	RES		0.9660E 03
PART	WT4	RO	COM		0.9660E 03
PART	WT4	RO	IND		0.4200E 03
PART	WT4	RO	UTL		0.4200E 03
PART	WT4	DO	RES		0.3360E 03
PART	WT4	DO	COM		0.3360E 03
PART	WT4	DO	IND		0.6300E 03
PART	WT4	DO	UTL		0.6300E 03
PART	WT4	CL	ALL	PV	0.1600E 05
PART	WT4	CL	ALL	CY	0.2000E 04
PART	WT4	CL	ALL	OF	0.1300E 05
PART	WT4	CL	ALL	SS	0.5000E 04
PART	WT4	CL	ALL	UF	0.5000E 04
PART	FT,CI,RES	GS	RES		0.1900E 02
PART	FT,CI,RES	GS	COM		0.1800E 02
PART	FT,CI,RES	GS	IND		0.1800E 02
PART	FT,CI,RES	GS	UTL		0.1800E 02
PART	FT,CI,RES	RO	RES		0.9660E 03
PART	FT,CI,RES	RO	COM		0.9660E 03
PART	FT,CI,RES	RO	IND		0.9660E 03

TABLE A-7 (Cont.)

Pollutant	Size	Fuel	User	Firing Type	Factor
PART	FT,CI,RES	RO	UTL		0.9660E 03
PART	FT,CI,RES	DO	RES		0.3360E 03
PART	FT,CI,RES	DO	COM		0.3360E 03
PART	FT,CI,RES	DO	IND		0.6300E 03
PART	FT,CI,RES	DO	UTL		0.6300E 03
PART	FT,CI,RES	CL	ALL	PV	0.1600E 05
PART	FT,CI,RES	CL	ALL	CY	0.2000E 04
PART	FT,CI,RES	CL	ALL	OF	0.1300E 05
PART	FT,CI,RES	CL	ALL	SS	0.5000E 04
PART	FT,CI,RES	CL	ALL	UF	0.5000E 04

Emission factors are in:

Gas - pounds pollutant per million cubic feet
Oil - pounds pollutant per thousand barrels
Coal - pounds pollutant per thousand tons

calculations for either the base year or projected years, so that all SO_2 and NO_x base-emission results correspond to the completely uncontrolled case.

Particulate control, on the other hand, is widely employed even in current installations. While several computer runs were made in which no control was included for comparison purposes, it was important to obtain estimates based on current and projected normal practices. Estimates of both collector efficiency and percent of units equipped with control devices were developed from statistical data collected by Riley Stoker and from discussions with other users and manufacturers.

The entries depend on equipment type and size, fuel, firing type, and age. The numbers in the table are the product of collector efficiency and fraction of units equipped with devices. The individual data (1967) on these quantities are shown in Table A-8. Strategies based on installation of more efficient or more widely used devices can be evaluated by overriding the entries in this file by a proper instruction in the STRAT interrogatory. The results of multiplying collector efficiency by fraction of units equipped is given in Table A-9. The units are fractions of particulate collected.

TABLE A-8

PARTICULATE CONTROL 1967 BASE YEAR
EQUIPMENT INSTALLATIONS AND EFFICIENCIES

Size Group	WT1,FT				WT2				WT3,WT4			
Boiler Size-#/hr	≤100,000				100,001 - 250,000				>250,000			
Age - Years	<10	11-20	21-30	>30	<10	11-20	21-30	>30	<10	11-20	21-30	>30
OIL	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	5_{80}	2_{75}	0_{-}	0_{-}
GAS	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}	0_{-}
COAL Pulv.	$-_{-}$	$-_{-}$	$-_{-}$	$-_{-}$	100_{90}	95_{80}	85_{70}	80_{60}	100_{98}	100_{95}	95_{90}	90_{80}
Cyclone	$-_{-}$	$-_{-}$	$-_{-}$	$-_{-}$	100_{90}	95_{80}	85_{70}	$-_{-}$	100_{98}	100_{95}	95_{90}	$-_{-}$
Stoker	20_{30}	10_{20}	0_{-}	$-_{-}$	85_{90}	80_{85}	70_{75}	60_{60}	90_{90}	80_{85}	70_{75}	60_{60}

KEY

% of units with → X_Y ← efficiency (%) of
control equipment   control equipment

TABLE A-9

PARTICULATE COLLECTOR EFFICIENCY TABLE

Size	Fuel	Age	Firing Type	Fraction Collected
WT1	GS	1		0.0
WT1	GS	2		0.0
WT1	GS	3		0.0
WT1	GS	4		0.0
WT1	RO	1		0.0
WT1	RO	2		0.0
WT1	RO	3		0.0
WT1	RO	4		0.0
WT1	CL	1	PV	0.900
WT1	CL	1	CY	0.900
WT1	CL	1	OF	0.060
WT1	CL	1	SS	0.060
WT1	CL	1	UF	0.060
WT1	CL	2	PV	0.760
WT1	CL	2	CY	0.760
WT1	CL	2	OF	0.020
WT1	CL	2	SS	0.020
WT1	CL	2	UF	0.020
WT1	CL	3	PV	0.595
WT1	CL	3	CY	0.595
WT1	CL	3	OF	0.0
WT1	CL	3	SS	0.0
WT1	CL	3	UF	0.0
WT1	CL	4	PV	0.480
WT1	CL	4	CY	0.480
WT1	CL	4	OF	0.0
WT1	CL	4	SS	0.0
WT1	CL	4	UF	0.0

TABLE A-9 (Cont.)

Size	Fuel	Age	Firing Type	Fraction Collected
WT2	RO	1		0.0
WT2	RO	2		0.0
WT2	RO	3		0.0
WT2	RO	4		0.0
WT2	CL	1	PV	0.900
WT2	CL	1	CY	0.900
WT2	CL	1	OF	0.765
WT2	CL	1	SS	0.765
WT2	CL	1	UF	0.765
WT2	CL	2	PV	0.760
WT2	CL	2	CY	0.760
WT2	CL	2	OF	0.680
WT2	CL	2	SS	0.680
WT2	CL	2	UF	0.680
WT2	CL	3	PV	0.595
WT2	CL	3	CY	0.595
WT2	CL	3	OF	0.525
WT2	CL	3	SS	0.525
WT2	CL	3	UF	0.525
WT2	CL	4	PV	0.480
WT2	CL	4	CY	0.480
WT2	CL	4	OF	0.360
WT2	CL	4	SS	0.360
WT2	CL	4	UF	0.360
WT3	RO	1		0.040
WT3	RO	2		0.015
WT3	RO	3		0.0
WT3	RO	4		0.0
WT3	CL	1	PV	0.980
WT3	CL	1	CY	0.980

TABLE A-9 (Cont.)

Size	Fuel	Age	Firing Type	Fraction Collected
WT3	CL	1	OF	0.810
WT3	CL	1	SS	0.810
WT3	CL	1	UF	0.810
WT3	CL	2	PV	0.950
WT3	CL	2	CY	0.950
WT3	CL	2	OF	0.680
WT3	CL	2	SS	0.680
WT3	CL	2	UF	0.680
WT3	CL	3	PV	0.855
WT3	CL	3	CY	0.855
WT3	CL	3	OF	0.525
WT3	CL	3	SS	0.525
WT3	CL	3	UF	0.525
WT3	CL	4	PV	0.720
WT3	CL	4	CY	0.720
WT3	CL	4	OF	0.360
WT3	CL	4	SS	0.360
WT3	CL	4	UF	0.360
WT4	RO	1		0.040
WT4	RO	2		0.015
WT4	RO	3		0.0
WT4	RO	4		0.0
WT4	CL	1	PV	0.980
WT4	CL	1	CY	0.980
WT4	CL	1	OF	0.810
WT4	CL	1	SS	0.810
WT4	CL	1	UF	0.810
WT4	CL	2	PV	0.950
WT4	CL	2	CY	0.950
WT4	CL	2	OF	0.680

TABLE A-9 (Cont.)

Size	Fuel	Age	Firing Type	Fraction Collected
WT4	CL	2	SS	6.80
WT4	CL	2	UF	6.80
WT4	CL	3	PV	0.855
WT4	CL	3	CY	0.855
WT4	CL	3	OF	0.525
WT4	CL	3	SS	0.525
WT4	CL	3	UF	0.525
WT4	CL	4	PV	0.720
WT4	CL	4	CY	0.720
WT4	CL	4	OF	0.360
WT4	CL	4	SS	0.360
WT4	CL	4	UF	0.360
FT	RO	1		0.0
FT	RO	2		0.0
FT	RO	3		0.0
FT	RO	4		0.0
FT	CL	1	PV	0.900
FT	CL	1	CY	0.900
FT	CL	1	OF	0.060
FT	CL	1	SS	0.060
FT	CL	1	UF	0.060
FT	CL	2	PV	0.760
FT	CL	2	CY	0.760
FT	CL	2	OF	0.020
FT	CL	2	SS	0.020
FT	CL	2	UF	0.020
FT	CL	3	PV	0.595
FT	CL	3	CY	0.595
FT	CL	3	OF	0.0

TABLE A-9 (Cont.)

Size	Fuel	Age	Firing Type	Fraction Collected
FT	CL	3	SS	0.0
FT	CL	3	UF	0.0
RES	RO	1		0.0
RES	RO	2		0.0
RES	RO	3		0.0
RES	RO	4		0.0
RES	CL	1	UF	0.0
RES	CL	2	UF	0.0
RES	CL	3	UF	0.0
RES	CL	4	UF	0.0
CI	RO	1		0.0
CI	RO	2		0.0
CI	RO	3		0.0
CI	RO	4		0.0
CI	CL	1	UF	0.0
CI	CL	2	UF	0.0
CI	CL	3	UF	0.0
CI	CL	4	UF	0.0

REFERENCES TO APPENDIX A

A-1. Fueloil and Oil Heat, page 62, April 1968.

A-2. Fueloil and Oil Heat, page 7, January 1968.

A-3. Steam-Electric Plant Factors, National Coal Association, Washington, D.C., 1968.

A-4. Shipment Statistics for Firetube Boilers, collected by the American Boiler Manufacturers Association, 1947-1969.

A-5. Annual Reports of the American Boiler Manufacturers Association on Watertube Boilers, 1948-1968.

A-6. Personal Communication with John I. Woodworth, Asst. General Manager of The Institute of Boiler and Radiator Manufacturers, August-September 1969.

A-7. Personal Correspondence with John I. Woodworth, Asst. General Manager of The Institute of Boiler and Radiator Manufacturers, August 1969.

A-8. 1968 Gas Facts, American Gas Association, Inc., New York.

A-9. "Statistical Highlights," Gas Appliance Manufacturers Association, 1969.

A-10. Current Industrial Report Series, Form MA-34G, U.S. Bureau of Census, 1967.

A-11. "County Business Patterns," U.S. Bureau of Labor Statistics, 1967.

A-12. Statistical Abstract of the United States, U.S. Bureau of the Census, Washington, D.C., 1968.

A-13. Mineral Industry Surveys, Annual "Shipments of Fuel Oil and Kerosene," U.S. Bureau of Mines, 1967.

A-14. Annual Industrial and Power Plant Surveys, Power, 1940-1968.

A-15. Shields, C. D., Boilers, McGraw-Hill, Inc., 1969.

A-16. ASHRAE Guide and Data Book, Systems and Equipment, ASHRAE, 1967.

A-17. Statistical Yearbook of the Electric Utility Industry for 1967, Edison Electric Institute, New York, 1968.

A-18. Blade, O. C., "Burner Fuel Oils 1967," Petroleum Products Survey No. 51, U.S. Bureau of Mines, August 1967.

REFERENCES TO APPENDIX A (continued)

A-19. 1969 Keystone Coal Buyers Guide, McGraw-Hill, New York, 1969.

A-20. Decarlo, J. A., et al., "Sulfur Content of U.S. Coals," U.S. BuMines, IC 8312, 1966.

A-21. Abernathy, R. F., et al., "Major Ash Constituents in U.S. Coals," U.S. BuMines, RI 7240, 1969.

A-22. Duprey, R. L., "Compilation of Air Pollutant Emission Factors," U.S. DHEW, PHS Publication No. 999-AP-42.

A-23. Mills, J. L., Luedtke, K. D., Woolrich, P. F., and Perry, L. B., "Emissions of Oxides of Nitrogen from Stationary Sources in Los Angeles County," Final Report, Los Angeles Air Pollution Control District, Los Angeles, California, July 1961.

APPENDIX B

METHODOLOGY FOR PROJECTIONS

Several techniques were used to arrive at projected boiler capacity. This section describes, in detail, the steps that were taken and the assumptions made. The results depend strongly on these various assumptions included in the projections analysis. The projections of boiler capacity itself and the distributive fuel and age factors were based on regression analyses of historical data and on trend extrapolation. Regional and user distributive factors were obtained from population and employment projections based on Bureau of Census and National Planning Associations estimates.

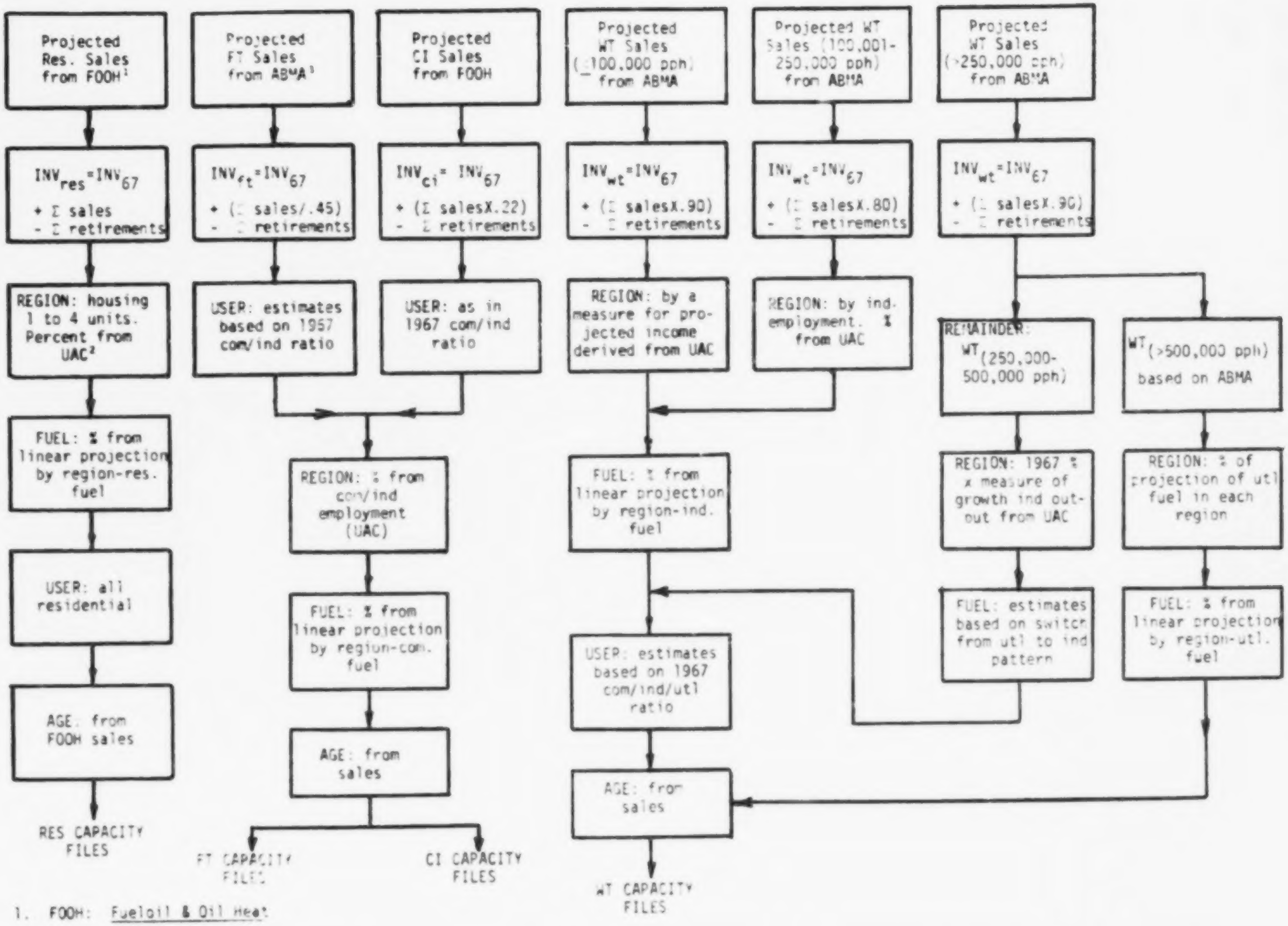
A flow chart indicating the main sources of data and order of operation used to obtain estimates of projected capacity is shown in Figure B-1.

A. REGRESSION ANALYSIS

By means of library statistical routines available on the time-sharing system used, regression analyses were performed for the various boiler categories. The yearly sales in each size/type category was considered to be the dependent variable in each regression equation in which relationships between these variables and other economic data were examined.

The specific method used was a stepwise regression method using yearly time series. The stepwise regression method is used to select independent variables in the order of importance and to incorporate them in a multiple linear regression model. The criterion of importance is based on the reduction of the sum of squares. The independent variable which reduces the sum by the largest amount in a given step is entered in the regression formula. The computer program was based on the abbreviated Doolittle method to calculate the various statistics.

The acceptance or rejection of the results was based principally on the following statistical information.


Projected Res. Sales from FOOH¹
INVres=INV67 + Σ sales - Σ retirements
REGION: housing 1 to 4 units. Percent from UAC²
FUEL: % from linear projection by region-res. fuel
USER: all residential
AGE: from FOOH sales
RES CAPACITY FILES
Projected FT Sales from ABMA³
INVft=INV67 + (Σ sales/.45) - Σ retirements
USER: estimates based on 1967 com/ind ratio
Projected CI Sales from FOOH
INVci= INV67 + (Σ salesX.22) - Σ retirements
USER: as in 1967 com/ind ratio
REGION: % from com/ind employment (UAC)
FUEL: % from linear projection by region-com. fuel
AGE: from sales
FT CAPACITY FILES
CI CAPACITY FILES
Projected WT Sales (≤100,000 pph) from ABMA
INVwt=INV67 + (Σ salesX.90) - Σ retirements
REGION: by a measure for projected income derived from UAC
Projected WT Sales (100,001-250,000 pph) from ABMA
INVwt=INV67 + (Σ salesX.80) - Σ retirements
REGION: by ind. employment. % from UAC
FUEL: % from linear projection by region-ind. fuel
USER: estimates based on 1967 com/ind/utl ratio
AGE: from sales
WT CAPACITY FILES
Projected WT Sales (>250,000 pph) from ABMA
INVwt=INV67 + (Σ salesX.90) - Σ retirements
REMAINDER: WT(250,000-500,000 pph)
REGION: 1967 % x measure of growth ind output from UAC
FUEL: estimates based on switch from utl to ind pattern
WT(>500,000 pph) based on ABMA
REGION: % of projection of utl fuel in each region
FUEL: % from linear projection by region-utl. fuel

1. FOOH: Fueloil & Oil Heat
2. UAC: Urban Analysis Corp.
3. ABMA: American Boiler Manufacturers Association

Figure B-1. Projected Inventory Distribution Flow Sheet.

1. The multiple correlation coefficient, a quantity related to the degree to which the relation of a dependent variable to a set of independent variables is exactly linear.

2. The F-statistic, a statistic related to the statistical significance of multiple correlation and used also in the analysis of variance of the regression equation. It is a function of the degree of freedom of the regression.

3. The t-statistic is a special case of F applied to the individual variables in the regression analysis.

4. The table of residuals shows the difference between the real values of the dependent variable and the values estimated by means of the resulting regression equation.

5. The standard error, which is the square root of the variance, is a measure of the accuracy of the estimate.

High multiple-correlation coefficients and highly significant F and t statistics were sought. Special attention was paid to the tables of residuals. For this study, the year-by-year prediction of boiler sales was not the most important factor. Year-by-year sales are needed to obtain the desired sums over various years to arrive at a new boiler inventory. For example, to obtain the new boiler inventory for 1975, the following equations would be used:

$$\text{Boilers } 75 = \text{Boilers } 67 + \sum_{t=1968}^{1975} (\text{Sales})_t - \sum_{t=1968}^{1975} (\text{retired boilers})_t \tag{B-1}$$

The accuracy of the forecasts accumulated over a number of years is of importance. Whereas individual year-to-year forecasts are not particularly accurate in several of the models below, their acceptance has been based on the residuals of the cumulative error in the prediction. The regression equations developed for each size/type class are shown below with a brief explanation. The historical data were obtained from the sources described above in the discussion of the 1967 basic capacity data [B-1,B-2].

Residential Boilers Sales (in thousands) = .0695 x Investment in Residental Structures (in millions of $) + 174 (B-2)

The multiple correlation coefficient is .955. After 1950 the error of the estimated sales is never larger than 12% of the real value and averages about 6%. The equations fits particularly well for the most recent years.

Cast Iron Boiler Sales (in thousands) = 5.78 x Investment in Residential Structures (in millions of $) + 85.2 (B-3)

The multiple correlation coefficient for this function is .841. The standard error is 7.6% of the mean of the dependent variable. The residuals for the recent years are practically insignificant. This equation was used to project total cast iron boiler sales, which includes residential boilers. It was found earlier that the percentage of cast iron boilers of the commercial/industrial type remained approximately constant over the years at about 19%, which percentage of the projected total will be used for this category of boilers.

In spite of a slightly cyclical pattern, firetube boilers sales were dominated by a linear time trend. The regression equation is:

Firetube Boiler Sales (in thousands of HP) = 38.99 x year - 75760 (B-4)

The multiple correlation coefficient is .970. The sales showed wider fluctuations in recent years causing several large errors. The yearly residuals had opposite signs, however, and thus largely disappeared in the sum, e.g., the sum of residuals over 1960-1968 was less than 1% of the sum of sales over this time period.

Watertube Boilers ≤100,000 pph (capacity in 10^6 lb of steam/hr) = .421 x Increase in National Income (in billions of $) - .697 x year + 1388 (B-5)

The multiple correlation coefficient is .790. This is a very complex group of boilers used in commercial and industrial enterprises as well as in utilities. Attempts to find better correlations were unsuccessful. The results of a correlation matrix seeking a better fit are shown below:

SALES OF WT BOILERS $\leq$100,000 pph

Variable	Correlation Coefficient
Non-Residential Investment	.254
Investment in Producers Durable Equipment	.276
Investment in Non-Residential Structures	.208
Gross Investment	.377
Increase in Commercial Employment	.564
Increase in Industrial Employment	.721

The results of the chosen regression were summarized in periods of 5 years and are shown below in Table B-1.

TABLE B-1

REGRESSION ANALYSIS - WATERTUBE BOILERS $\leq$100,000 pph

	Actual Sales	Estimated Sales	Residual	Percent of Actual Sales
1949-1953	169.1	170.7	1.6	1.0
1954-1958	148.4	145.9	-2.5	-1.6
1959-1963	143.2	150.1	6.9	4.8
1964-1968	188.1	182.4	-5.7	-3.0

As can be seen the summarized residuals are quite small and the regression equation was considered acceptable.

Watertube Boilers 100,001-250,000 pph (capacity in 10^6 pph) =
.448 x Increase in National Income (in billions of \$) -
2.225 x Year + 1.444 x Investment in Non-Residential Structures
(in billions of \$) + 4339

(B-6)

The multiple correlation coefficient is .890. Again the results were summarized to determine whether the residuals would cancel out. The summary shown below (Table B-2) was quite favorable. This result together with the other statistical information made the regression equation acceptable.

TABLE B-2

REGRESSION ANALYSIS - WATERTUBE BOILERS 100,001-250,000 pph

	Actual Sales	Estimated Sales	Residual	Percent of Actual Sales
1949-1953	102.6	102.2	0.4	0.4
1954-1958	79.7	76.6	3.1	3.9
1959-1963	57.7	62.1	-4.4	-7.6
1964-1967	89.3	88.4	0.9	1.0

$$\begin{aligned}&\text{Watertube Boilers} >250{,}000\text{ pph (capacity in } 10^6\text{ pph)} = 4.121 \times \\ &\quad \text{Gross Investment (in billions of \$)} - 10.625 \times \text{Year} + 20598\end{aligned} \qquad \text{(B-7)}$$

The multiple correlation coefficient is .920. The standard error was high, but upon examination of the table of residuals, it was found that this was caused by five specific cases.

In 1956 far more capacity was sold than the regression equation shows. Conversation with several boiler manufacturers emphasized the fact that these high sales were totally unexpected and could not be accounted for in an economically rational way. It is very unlikely that as rough a prediction model as the one above would be able to predict such an anomaly.

The other four cases of large residuals appear to be a consequence of economics and of the time scale of the data. In 1961 and 1962 the model result is respectively too high and too low in its predictions. The same is the case for the sales predictions for 1966 and 1967. Sales data were available only on a yearly basis from the ABMA, making it impossible to include variables lagged by one or two quarters, which pattern is typical of investment functions. The relationship between the sales of these large watertube boilers and variables lagged by one year (which was the shortest time lag that could be introduced) was inferior to the results of the equation shown above, and was therefore discarded.

Since the residuals in these cases are of opposite signs, however, it is believed that the problem is not serious. The table (Table B-3) shows the summarized results.

TABLE B-3

REGRESSION ANALYSIS - WATERTUBE BOILERS >250,000 pph

	Actual Sales	Estimated Sales	Residual	Percent of Actual Sales
1949-1953	357.9	373.6	-15.7	-4.4
1954-1958	419.8	404.8	15.0	3.6
1959-1963	463.2	461.7	1.5	0.3
1964-1967	725.5	726.1	-0.6	-0.1

It is noted that these equations form a rough model, which does not give accurate predictions of sales on a year-by-year basis, but which fits the boiler sales over a five year period or a longer period within 10 percent of the real value, if not better.

B. SALES PROJECTIONS

The model is summarized below in abbreviated form.

$$\text{Res} = .0695 \times I_R \times 10^{-3} + 174 \qquad \text{(B-8)}$$

$$\text{CI} = 5.78 \times I_R + 85.2 \qquad \text{(B-9)}$$

$$\text{FT} = 38.99 \times \text{YR} - 75760 \qquad \text{(B-10)}$$

$$\text{WT}_{<100} = .421 \times \Delta\text{NI} - .697 \times \text{YR} + 1388 \qquad \text{(B-11)}$$

$$WT_{100\text{-}250} = .448 \times \Delta NI - 2.225 \times YR + 1.444\ I_{NR} + 4339 \qquad \text{(B-12)}$$

$$WT_{>250} = 4.121 \times I - 10.625 \times YR + 20598 \qquad \text{(B-13)}$$

where I_R = investment in residential structures in billions of \$

YR = year

ΔNI = the difference between the national income of the year concerned and the previous year in billions of \$

I_{NR} = investment in non-residential structures in billions of \$

I = gross investment in billions of \$

To find projected values for the dependent variables, it is necessary to complete this model. The five independent variables shown above determine the behavior of the model. Given a means to project these variables, projected boiler sales can then be estimated. The Brookings economic model of the U.S. economy, using quarterly data, would provide the complex relationships determining the various investment functions and national income. The ideal solution of this model would be to add the necessary relationships found in the Brookings model to determine the independent variables. This procedure would require much detail and a large labor effort. As such, the methodology was simplified to include only the following steps:

(a) Perform regression analysis as a function of time for the "independent" variables.

(b) Find forecasts for these variables from 1968 through 2000 based on the results above.

(c) Substitute the forecasted values for I_R, ΔNI, I_{NR}, and I into the boiler model and find the sales for each type for the years 1968 through 2000.

These steps are equivalent to the assumptions that all the independent variables are exogenous (i.e., determined outside the system) and follow a linear time trend. This idealized approach removes all cyclical components from the model. It is believed that the introduction of error in the predicted exogenous variables is less offensive than errors in the model itself. If, at a later stage, it is found worthwhile to insert values predicted by means of a sophisticated econometric model such as that of the Brooking Institute, the model would show better predictions without the model itself having to be changed. For the purposes of this study, the linearization described above should not be considered as a limitation since the projections were needed over periods of at least five years and the cycles would more or less cancel out, as shown above.

The results for watertube boilers between 100,001 and 250,000 pph were unsatisfactory and were adjusted. Figure B-2 shows the sales of these boilers for the years 1949-1968. The increasing trend when projecting backwards in time appears unlikely. It was assumed rather that, as indicated by sales during the 1960's, the trend will be upward in the future. The regression function was rerun for this intermediate watertube category using only the 1961-1968 time series in order to project the increasing trend. The result is shown below:

$$WT_{100-250} = 204 \times \Delta NI + .149 \times YR + .851 \times I_{NR} - 303 \qquad \text{(B-14)}$$

The pattern in Figure B-2 appears to be attributable to the following factors. After World War II, larger boilers were being sold to utilities than were sold before the war. These boilers were larger than 250,000 pph and were substituted where previously a similar power plant would have used one or two boilers of a smaller watertube category. The popularity of this 100,001-250,000 pph size group decreased relatively and absolutely during the fifties. Economic growth in the sixties, however, increased the demand for all boilers, including those between 100,000 and 250,000 pounds of steam per hour, resulting in an upward trend in the total capacity sold in this size group once more. Also, the introduction of packaged watertube boilers in this size group increased sales. Sales projections based on Equation (B-14) were used.

Prior to calculating the new inventories, the following points were taken into account: actual sales data, available for 1968 and 1969, were used instead of the predicted values. The predicted values were adjusted according to their source. Only 20% of the cumulative cast iron

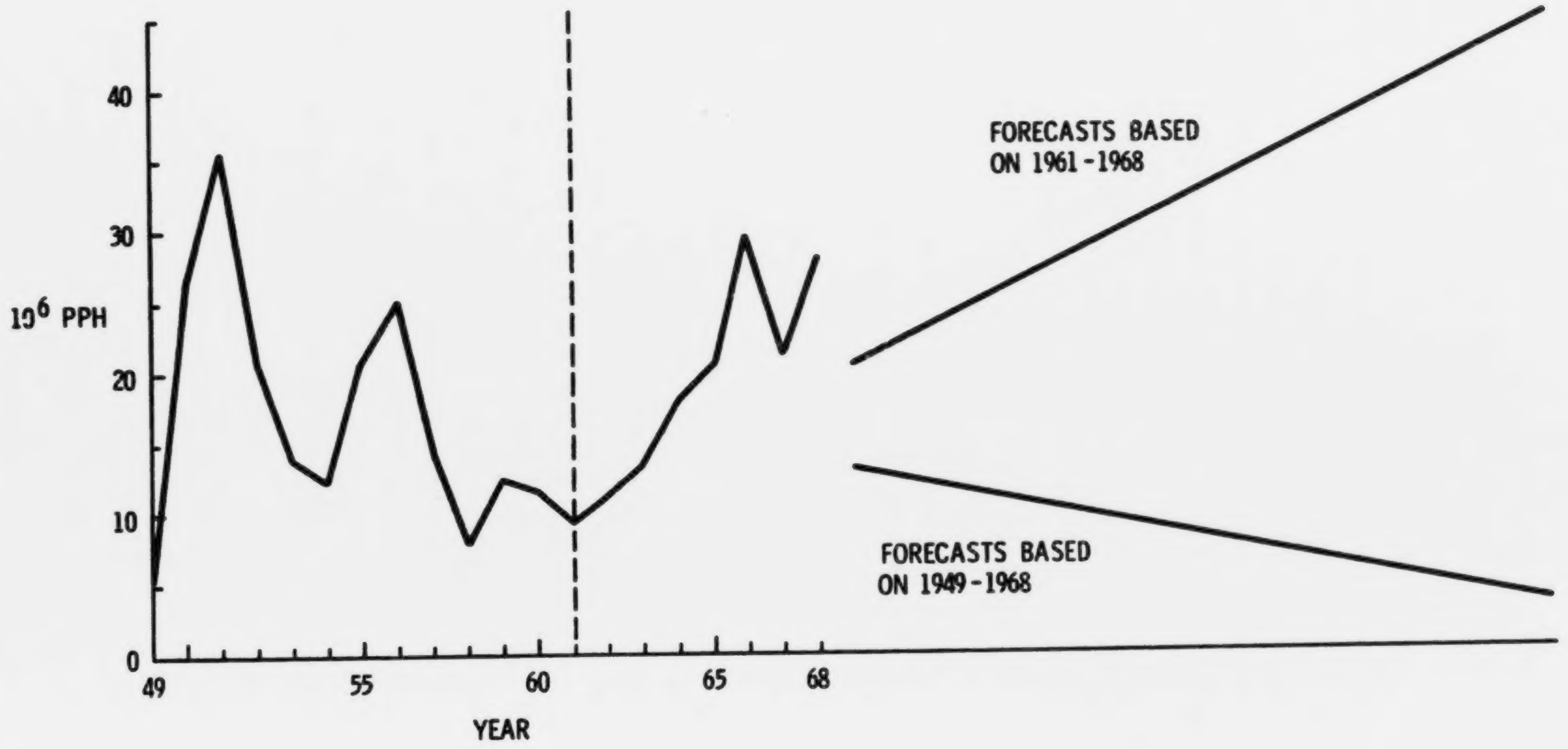


Figure B-2. Historical and Projected Sales of Watertube Boilers, 100,001-250,000 pph.

forecasts was estimated to be of the commercial/industrial type in 1973, 22 percent in 1978 and 25 percent in 1988. The firetube forecast represented only about 45 percent of the total market, since it was derived from ABMA sales figures only. It was necessary to compensate for this and the forecasts were adjusted upwards to represent the entire market. Watertube forecasts were adjusted to exclude exports, and lagged to account for delivery times of one, two and three years for the smallest, medium, and large sizes, respectively.

The results of these operations are summarized in Table B-4.

C. RETIREMENTS

The last step in estimating the installed capacity in the projected years is to deduct retirements from the totals in Table B-4. In order to obtain an estimate of the retired boilers during each period the procedure was to deduct the sales during as many of the earliest years as were being added. For example, in order to arrive at the capacity of watertube boilers retired in the five year period after 1967, the sales for the earliest five years, 1915-1919 adjusted to exclude exports, were subtracted (First In-First Out basis). The results are summarized below in Table B-5.

D. PROJECTIONS OF INSTALLED CAPACITY

The results of adding new capacity and subtracting retirements are shown in Table B-6 (and earlier in the results sections). The over-250,000 pph watertube category must be split into the intermediate fraction and the over-500,000 pph size to conform to the proper size classes used in the study. The results are shown in the bottom two lines in Table B-6. The means by which the split was made are discussed below.

Recent ABMA reports contained sufficient data to determine the fraction of boiler capacity sold consisting of units greater than 500,000 pph, see Table B-7.

The percentage of sales in the larger size segment has been plotted in Figure B-3. Linear extrapolation would quickly exceed 100%.

TABLE B-4

ADDED BOILERS

Time Period	RES (thou. units)	CI (thou. units)	FT (thou. HP)	$WT_{<100}$ (10^6 pph)	$WT_{100-250}$ (10^6 pph)	$WT_{>250}$ (10^6 pph)
1968-1975	19,350	435.2	19,710	235	157	1,386
1976-1980	14,000	334.1	15,135	147	116	998
1981-1985	15,470	393.7	17,300	148	138	1,152
1986-1990	16,930	440.6	19,465	148	160	1,307

TABLE B-5

RETIRED BOILERS

Time Period	RES (thou. units)	CI (thou. units)	FT (thou. HP)	$WT_{<100}$ (10^6 pph)	$WT_{100-250}$ (10^6 pph)	$WT_{>250}$ (10^6 pph)
1968-1975	12,800	181.5	3,570	111	115	43
1976-1980	9,600	151.8	1,900	69	72	29
1981-1985	10,950	94.7	3,690	70	72	32
1986-1990	11,650	173.3	5,990	74	72	40

TABLE B-6

PROJECTED INSTALLED CAPACITY

Type	Units	1967	1975	1980	1985	1990
Residential	10^3 units	29,749	36,297	40,694	45,214	50,492
Cast Iron	10^3 units	1,273	1,526	1,709	2,008	2,275
Firetube	10^6 pph	813	1,345	1,782	2,231	2,675
Watertube$_{<100}$	10^6 pph	921	1,045	1,123	1,201	1,275
Watertube$_{100-250}$	10^6 pph	658	700	744	810	898
Watertube$_{>250}$	10^6 pph	1,507	2,850	3,819	4,939	6,206
Watertube$_{250-500}$	10^6 pph	259	286	282	276	262
Watertube$_{>500}$	10^6 pph	1,248	2,564	3,537	4,663	5,944

TABLE B-7

RECENT LARGE BOILER SALES (ABMA)

(Capacity in 10^6 pph)

	>250,000 pph	>500,000 pph	Percent**
1963	118.4	98.2	82.9
1964	149.6	135.8	90.8
1965	190.7	172.7	90.6
1966	178.0	no data (163.7)*	(92.0)
1967	207.2	197.8	95.5
1968	199.5	189.9	95.2

---

*estimated

** $\frac{>500}{>250} \times 100$

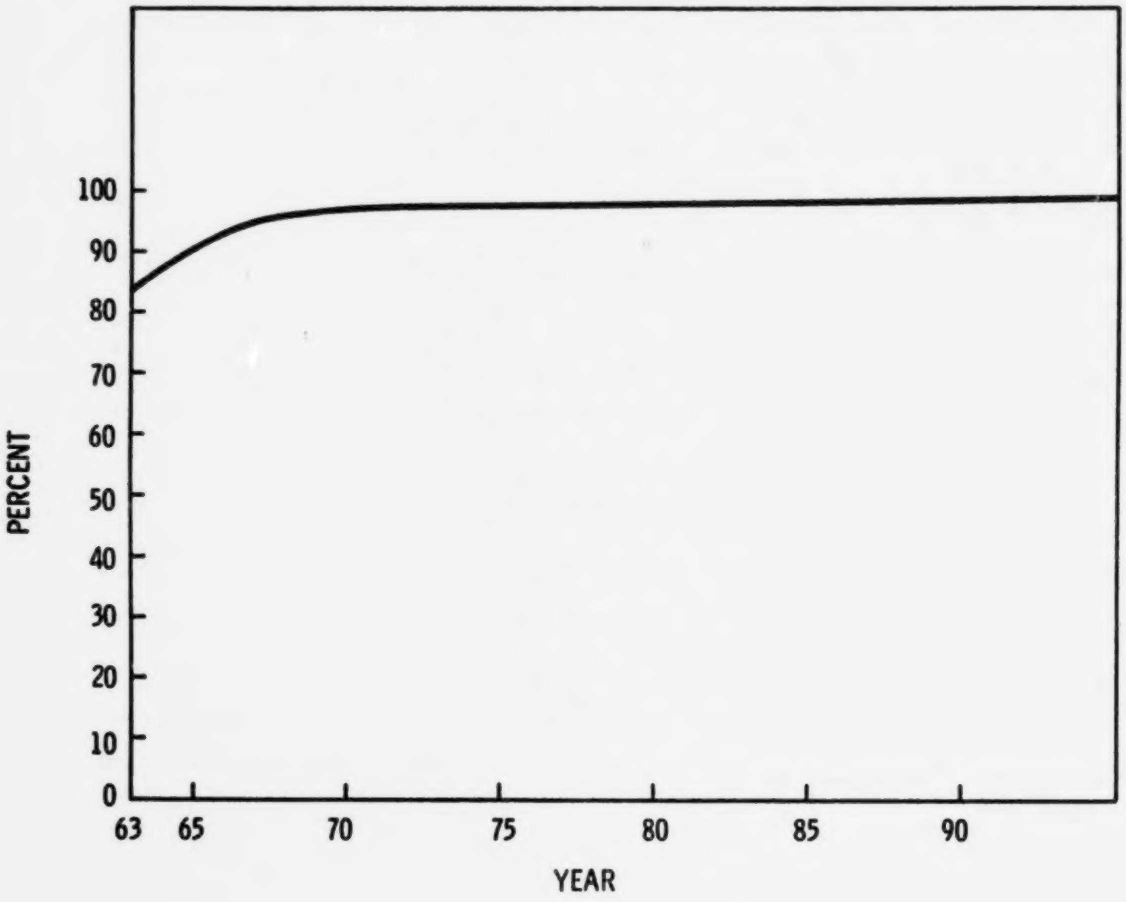


Figure B-3. Projected Percentage of Watertube Boilers >500,000 pph in the Set >250,000 pph

A curve which approaches 100% has been fitted subjectively to the data. The rapid approach to 100% leveling off can be attributed to the lumping together of all boilers over 250,000 pph in a single category. The sales in this range are completely dominated by the few huge boilers, each over 5,000,000 pph, sold each year. Boilers this size have been developed and sold only in the past decade.

The percentages read from the curve in Figure B-3 were used to distribute added sales. Exports were assumed to be 10% of the total, as has been the general experience for about 20 years. No retirement in the over-500,000 pph boiler class is assumed through 1990.

It is noted that the remaining capacity in the 250,001-500,000 pph size group is diminishing slightly. This trend appears to result from the following factors:

(1) Utilities, which had historically been the main buyers of the 250,001-500,000 pph boilers are presently installing much larger boilers.

(2) Smaller utilities are installing larger boilers and sharing them through interconnected systems.

Consequently, it is possible that more old boilers are being retired in this size category than are being added. The tremendous growth in the combined classes >250,000 pph is entirely due to the growth for the greater than 500,000 pph boilers, which are not included in the intermediate category of this study.

E. REGIONAL, FUEL, USER DISTRIBUTION

1. Residential Boilers - Regional distribution was obtained according to housing of one to four units in each region. Projections for housing were obtained for Walden by Urban Analysis Corporation (see Section F below). CL, DO, RO, GS distribution according to region was made by applying residential percentages obtained from projections based on present trends of fuel usage (see Section G below). The average size of the residential boilers was assumed to be increasing slightly based on conversations with various boiler manufacturers.

100,000 Btu/hr (input rating) in 1967
110,000 Btu/hr (input rating) in 1975
115,000 Btu/hr (input rating) in 1980
118,000 Btu/hr (input rating) in 1985
120,000 Btu/hr (input rating) in 1990

The age distribution was recalculated by properly accounting for new sales and retirements. This calculation was made at the same time the new inventory was compiled.

2. Cast Iron Boilers - The boilers were distributed over the commercial/industrial categories in the same ratio (80%/20%) as was used in 1967 for all the projected years. Any change, if any, over the years in the relative use of these boilers will be insignificant. Regional distribution was made in proportion to the employees in the commercial/industrial categories respectively. Projections for employment were obtained for Walden by Urban Analysis (see Section F below). CL, DO, RO, GS distribution by region was calculated using the commercial fuel distribution for the projected years, obtained from projections based on present trends of fuel usage. The average size of these cast iron boilers is expected to increase by 5% between 1967-1975, 3% between 1975-1980, 2% between 1980-1985, and 0 between 1985-1990. Age distribution was determined as above.

3. Firetube Boilers (Commercial/Industrial) - These boilers were distributed over the commercial/industrial categories in the following ratios:

	Commercial	Industrial
1967	56%	44%
1975	54%	46%
1980	52%	48%
1985	50%	50%
1990	48%	52%

It was assumed here that the average size firetube boilers used by commercial enterprises will not change with time, whereas the average size of industrial firetube boilers would tend to increase. This factor accounts for the increasing industrial share of firetube capacity. Regional distribution was obtained by using employment figures in the commercial/industrial categories respectively. CL, DO, RO, GS distribution was calculated by using the commercial fuel distribution for the projected years obtained from projections based on present trends of fuel usage, below. The average size for the firetube boilers was projected by means of a linear regression resulting in the following values for the projected years.

	Average Size FT Boilers (HP)
1975	135
1980	160
1985	180
1990	200

Age distribution was determined as above.

4. Watertube Boilers ≤100,000 pph - In the national projections this category was found to be a function of the increase in national income and the time trend. Projected figures were made available by Urban Analysis Corporation for industrial output by region as a proportion of 1967. A measure of projected income was obtained by multiplying these ratios by 1967 regional personal income figures. The watertube boilers in this smallest category were distributed over the regions proportional to these figures. Regional CL, DO, RO, GS distribution was calculated using the industrial fuel distribution, obtained from projections based on present trends of fuel usage, below. The average size for these watertube boilers was estimated by extrapolation of historical data. The results are shown below:

	Average Size $^{WT}\leq 100{,}000$ (in 10^3 pph)
1967	27
1975	37
1980	42
1985	47
1990	52

Age distribution was determined as above.

5. Watertube Boilers - 100,001-250,000 pph - These boilers are mostly of the industrial type and were distributed over the various regions according to industrial employment. The CL, DO, RO, GS distribution was calculated for each region using the industrial fuel distribution, obtained from projections based on present trends of fuel usage below. The average size of these watertube boilers was not expected to change significantly and was estimated at about 155,000 pph for the years of projection. Age distribution was determined as above.

6. Watertube Boilers - 250,001-500,000 pph - The regional distribution for these boilers was found by multiplying the 1967 percentages for regional distribution for this size group by regional industrial output ratio, and adjusting this figure so that the six regions add up to 100%. In recent years about 90% of the boilers sold in this size group are for industrial use and only 10% go to the utilities industry. The fuel distribution of this size group in each region in 1967 was closer to the utilities fuel use pattern than the industrial. This distribution will in the future shift towards the industrial fuel distribution. The percentages have been changed only slightly using this assumption for the year of projection, since the projections show a stagnant development in this size group of watertube boilers. The average size of these watertube boilers is expected to remain approximately the same. Age distribution was determined as above.

7. Watertube Boilers >500,000 pph - Since these boilers are 95-97% utilities and only 3-5% industrial, the regional distribution

was obtained from the percentages of projected total utilities fuel use in each region. The fuel distribution in each region was made according to the projected utilities fuel percentages in each region. The average size of watertube boilers in this class is expected to increase substantially. A rough estimate was made and the following figures were used:

1967	1,185,000 pph
1975	1,350,000 pph
1980	1,475,000 pph
1985	1,625,000 pph
1990	1,750,000 pph

Age distribution was determined as above.

F. PROJECTIONS OF DEMOGRAPHIC AND ECONOMIC FACTORS

Urban Analysis Corporation provided population and economic projections for this study, which projections were used to distribute projected total capacity over the various regions and to calculate priority factors. The original tables of data are extensive and are not contained in this report. Some regional summaries are presented [B-3].

The economic and population projections have three primary objectives:

(1) To provide reasonable indicators of the future economic and population changes which will affect the volume and regional distribution of emissions from fossil-fuel combustion equipment.

(2) To achieve compatibility and comparability of this study with other studies.

(3) To facilitate future updating of the study.

Toward these ends, existing projections have been used wherever possible and reasonable, with preference given to those most widely accepted and those which are periodically updated.

1. Population - The three major sources used for the population porjections are described below:

(a) The Census estimates and projections are published in the U.S. Census Bureau's Current Population Reports, Series P-25. The specific reports used are:

Numbers 72 (Table 1), 304 (Table 2), 380 (Table 1) and 414 (Table 3) for population estimates.

Numbers 375 (Table 1) and 381 (Table A) for population projections.

The Census Bureau's state and national estimates and national projections, probably more than any other population and economic series, have earned general respect, acceptance, and near universal use. In making state projections, which include less certain components, the Census Bureau's projections are not so generally accepted since they make only crude attempts to reflect the shifts in economic activity. But their state projections do have the advantages of careful consideration of birth and death rates and a projection of age distribution. All the Census series offer the additional advantage of frequent review followed by publication, in the Series P-25, of resulting adjustments.

(b) The National Planning Association (NPA) projections are published in its annual national and regional reports. The report used here is the Economic and Demographic Projections for States and Metropolitan Areas, Report No. 68-R-1, of January 1969. These projections build upon the Census Bureau's state and national estimates and national projections of population. These are probably the best known and most generally-accepted state projections, being a relatively careful attempt to project and reflect probable economic activity. Like the Census Bureau, the NPA projections are regularly reviewed.

(c) The preliminary projections prepared by the U.S. Office of Business Economics (OBE) are generally consistent at the national level with the above projections. Its 167 regions are aggregates of counties and attempt to delineate metropolitan spheres of influence. To the extent that its delineation is accurate, the regions offer some advantages in locating the geographic impact of metropolitan growth. But because the regions ignore state boundaries, they are difficult to relate to other data and are less adaptable to state government affairs. (Only in Hawaii and Alaska do they correspond to state boundaries and Arizona is the only additional state in which these regions can be aggregated to state boundaries.) Because of these difficulties, the NPA projections were used. The OBE projections, being official government projections and using somewhat more sophisticated methodology, would otherwise have been preferred.

2. Households - The projections of households include all occupied housing units. They exclude vacant housing units. A household is defined as a family or other group of persons who together occupy a house, an apartment, or other group of rooms. The projections distinguish between households residing in metropolitan areas and those living outside metropolitan areas. For each of these two groups, the projections further distinguish between those residing in structures containing one to four dwelling units and those residing in structures with five or more dwelling units.

The Census Bureau's Series 2 projection of households provides the basis for these projections. The other Census Bureau projection (Series 1) and a projection by Irving Silver of MIT are used to provide a range of assumptions for testing sensitivity.

3. Employment - Employment is average annual employment. It is equivalent to the full-time and part-time jobs reported by the Survey of Current Business [B-4]. It has been determined in three levels of detail: (a) total, (b) Standard Industrial Classification (SIC) "Divisions" ("one-digit" industries) and (c) selected two-digit SIC categories.

The figures for total and divisional employment are those developed by the National Planning Association (NPA), based upon the primary statistics of the Census, the Bureau of Labor Statistics and County Business Patterns, but include adjustments to correct for incomplete coverage and conflicts in definitions.

The two-digit SIC categories are those which have been identified as of primary importance to the study. The 1967 figures are based upon the Bureau of Labor Statistics' reports of statistics gathered by the state employment security offices. They are adjusted to correct for incomplete coverage and reporting. The NPA does not make state projections of two-digit categories so their national two-digit projections are used to allocate their first-digit state projections.

4. Industrial Output - The industrial output series indicate changes in production, reflecting both changes in number of persons employed and changes in productivity per employee. Practical and reliable measures of gross product for sub-national regions have not yet been developed. Such problems as the allocation of profits of the large national corporations have yet to be resolved. The series developed here do not pretend to measure production levels. Instead they attempt only to indicate change in production by applying, on an industry basis, the projected changes in the national average productivity per employee to the projected employees in each state. Being indicators of changes rather than levels of production, the series are represented as ratios of each projected year to the 1967 base year.

The measure of output is constant dollar gross product originating by industry. It includes employee compensation, capital consumption allowances, net interest, indirect business taxes, business transfer payments, and profits-type income.

The ratios are derived from the employment projections and NPA projections of national changes in output per employee to each industry. The ratios assume no changes in the state differences in output per employee.

5. Projected Data - Summary tables of households, employment-manufacturing, employment-commercial, and industrial output follow (Tables B-8 through B-11).

G. LINEAR FUEL PROJECTIONS

In order to properly distribute capacity by fuel type it was necessary to develop estimates of fuel percentages by region for the several projected years. These estimates were obtained by means of linear regressions based on historical data, using at least three and, at most, five points.

State-by-state data were compiled showing coal, oil, and gas consumption by user categories. The same methodology used in treating 1967 fuel-use data was used to distribute raw fuel-use data by user. These data were summarized by region and user for each year, and projected for the years 1975, 1980, 1985, and 1990. The percentage of the fuel estimated to be burned under boilers in 1967 was applied depending on the type of fuel and user. The four fuel totals thus obtained by region and user were expressed in percentages, and were adjusted where necessary. These adjustments were applied when the linear trends indicated an overly rapid decrease in the consumption of coal. It was felt that, although the consumption of coal by commercial and industrial establishment has been rapidly declining in most regions, this decline would start slowing down and become a more or less asymptotic function. With this consideration incorporated in the treatment of the raw data, the figures obtained from the regression analysis, expressed as percentages, are summarized below (Tables B-12 through B-15). The adjustment reflects non-linearities in fuel-use patterns. Coal use has declined rapidly in industrial and commercial installations and all but disappeared in domestic use. Resistance builds up due to saturation, limited supply and higher costs of other fuels. The adjustments from the linear trend projections represent a reasonable estimate of the impact of these factors. Accuracy in projecting coal use is significant since coal produced relatively larger emissions of all three pollutants than its proportion of fuel use on an energy basis.

TABLE B-8

HOUSEHOLDS (1 to 4 UNITS)
(in thousands)

	1975	1980	1985	1990
AT	13,902.3	14,912.1	15,822.9	16,684.3
GL	11,301.1	12,112.1	12,972.9	13,787.0
WS	16,020.2	17,845.7	19,663.3	21,109.7
CU	6,890.9	7,329.9	7,768.9	8,185.5
SE	8,159.1	8,894.3	9,601.4	10,329.6
RN	1,635.9	1,763.9	1,893.4	2,022.6
TOTAL	57,909.5	62,858.0	67,722.8	72,119.0

TABLE B-9

EMPLOYMENT - MANUFACTURING
(in thousands)

	1975	1980	1985	1990
AT	6,671.0	6,653.4	6,749.8	6,943.2
GL	5,575.7	5,661.0	5,816.5	6,071.1
WS	3,989.0	4,321.5	4,645.5	4,998.8
CU	3,141.8	3,340.3	3,565.8	3,721.2
SE	1,839.9	1,937.2	2,043.5	2,147.8
RN	390.7	400.6	413.7	430.8
TOTAL	21,609.1	22.314.0	23,234.8	24,312.9

TABLE B-10

EMPLOYMENT - COMMERCIAL

(in thousands)

	1975	1980	1985	1990
AT	12,422.5	13,384.6	14,146.9	15,171.6
GL	7,416.5	7,928.5	8,363.1	8,969.7
WS	10,286.8	11,377.3	12,379.5	13,438.3
CU	4,297.7	4,691.3	5,046.2	5,399.2
SE	4,046.6	4,539.3	4,981.1	5,341.4
RN	885.4	948.6	1,005.9	1,072.0
TOTAL	39,355.5	42,869.6	45,922.7	49,392.2

TABLE B-11

INDUSTRIAL OUTPUT AS A PROPORTION OF 1967

	1975	1980	1985	1990
AT	1.4048	1.7505	2.1426	2.6525
GL	1.3731	1.6877	2.0539	2.5405
WS	1.4975	1.9343	2.4497	3.1463
CU	1.4150	1.7851	2.2238	2.7514
SE	1.4348	1.8370	2.3202	2.8612
RN	1.3928	1.7392	2.1563	2.6630

TABLE B-12

FUEL PROJECTIONS FOR FUEL BURNED IN INTERMEDIATE BOILERS - 1975

(in percent of regional total)

	CL	RO	DO	GS
		UTILITIES		
AT	70.2	23.9		5.8
GL	98.9	.1		1.0
WS	4.2	12.4		83.4
CU	45.9	.9		53.2
SE	95.1	.1		4.8
RN	90.8	6.7		2.5
		INDUSTRIAL		
AT	28.2	53.8	2.9	15.1
GL	58.8	8.7	1.6	30.9
WS	1.8	10.7	1.4	86.2
CU	19.3	12.9	1.2	66.7
SE	46.3	12.0	1.0	40.7
RN	4.8	37.7	7.7	49.8
		COMMERCIAL		
AT	3.0	50.0	30.0	17.0
GL	11.6	12.9	13.4	62.1
WS	2.0	10.7	4.4	82.9
CU	7.8	6.3	6.7	79.2
SE	13.5	6.8	10.0	69.7
RN	11.4	16.8	22.7	49.1

TABLE B-12 (Cont.)

	CL	RO	DO	GS
		RESIDENTIAL		
AT			64.6	35.4
GL			33.4	66.6
WS			13.1	86.9
CU			24.1	75.9
SE			30.2	69.8
RN			73.2	26.8

TABLE B-13

FUEL PROJECTIONS FOR FUEL BURNED IN INTERMEDIATE BOILERS - 1980

(in percent of regional total)

	CL	RO	DO	GS
		UTILITIES		
AT	68.9	25.1		5.9
GL	98.9	.1		1.0
WS	4.4	11.6		84.0
CU	46.5	.8		52.7
SE	95.6	.1		4.3
RN	92.8	5.2		2.0
		INDUSTRIAL		
AT	23.9	56.8	2.7	16.6
GL	56.5	7.6	1.5	34.3
WS	1.6	9.7	1.4	87.3
CU	14.5	13.8	1.2	70.5
SE	44.2	12.4	1.0	42.4
RN	3.8	41.0	9.6	45.6
		COMMERCIAL		
AT	2.4	50.7	29.7	17.2
GL	7.7	12.9	13.8	66.1
WS	1.3	8.9	4.2	85.5
CU	3.6	6.0	6.6	83.8
SE	11.8	6.9	10.2	71.1
RN	6.2	17.7	23.8	52.3

TABLE B-13 (Cont.)

	CL	RO	DO	GS
		RESIDENTIAL		
AT			63.7	36.3
GS			33.0	67.0
WS			11.8	88.2
CU			23.3	76.7
SE			30.4	69.6
RN			73.1	26.9

TABLE B-14

FUEL PROJECTIONS FOR FUEL BURNED IN INTERMEDIATE BOILERS - 1985

(in percent of regional total)

	CL	RO	DO	GS
		UTILITIES		
AT	67.9	26.0		6.0
GL	98.9	.1		1.0
WS	4.5	11.1		84.4
CU	46.9	.7		52.4
SE	95.9	.1		4.0
RN	94.3	4.1		1.7
		INDUSTRIAL		
AT	20.1	59.5	2.5	17.9
GL	54.5	6.6	1.5	37.4
WS	1.5	8.9	1.4	88.2
CU	10.2	14.7	1.2	73.9
SE	42.4	12.8	1.0	43.8
RN	3.2	33.2	8.7	54.9
		COMMERCIAL		
AT	1.0	51.6	30.0	17.4
GL	3.0	13.9	9.0	74.1
WS	.7	7.5	4.1	87.7
CU	1.0	5.5	6.5	87.0
SE	5.0	7.4	11.0	76.6
RN	3.0	18.0	24.3	54.7

TABLE B-14 (Cont.)

	CL	RO	DO	GS
		RESIDENTIAL		
AT			63.0	37.0
GL			32.6	67.4
WS			10.7	89.3
CU			22.6	77.4
SE			30.6	69.4
RN			73.0	27.0

TABLE B-15

FUEL PROJECTIONS FOR FUEL BURNED IN INTERMEDIATE BOILERS - 1990

(in percent of regional total)

	CL	RO	DO	GS
		UTILITIES		
AT	67.1	26.8		6.1
GL	98.9	.1		1.0
WS	4.6	10.6		84.8
CU	47.2	.7		52.1
SE	96.2	.1		3.7
RN	95.4	3.2		1.4
		INDUSTRIAL		
AT	16.6	61.9	2.4	19.1
GL	52.6	5.8	1.4	40.2
WS	1.4	8.2	1.5	88.9
CU	6.2	15.5	1.2	77.1
SE	40.8	13.1	1.0	45.0
RN	2.4	3.13	9.2	57.1
		COMMERCIAL		
AT	0	52.0	30.0	18.0
GL	0	13.1	14.4	72.5
WS	0	6.3	4.0	89.7
CU	0	5.1	6.3	88.6
SE	0	7.8	11.6	80.6
RN	0	18.6	25.1	56.3

TABLE B-15 (Cont.)

	CL	RO	DO	GS
		RESIDENTIAL		
AT			62.4	37.6
GL			32.3	67.7
WS			9.8	90.2
CU			22.1	77.9
SE			30.7	69.3
RN			73.0	27.0

REFERENCES TO APPENDIX B

B-1. Personal Correspondence with John I. Woodworth, Asst. General Manager of The Institute of Boiler and Radiator Manufacturers, August 1969.

B-2. Annual Reports of the American Boiler Manufacturers Association on Watertube Boilers, 1948-1968.

B-3. "Final Report on Population and Economic Projections," Urban Analysis Corporation, June 1, 1970.

B-4. "The National Income and Product Accounts of the United States 1929-1965," U.S. Dept. of Commerce, Office of Business Economics, 1970.

APPENDIX C

SUMMARY DATA TABLES OF SELECTED STRATEGIES

Of the hundreds of possible strategies, many were not given serious consideration after preliminary evaluation of the range of their pollutant reduction potential, or of their capital or operating cost. Examples of such discarded strategies are:

Description	Comment
National fuel switch to gas	Effective but impractical because of fuel cost and availability
High efficiency particulate collectors	Not practical for smaller units; no effect on other pollutants
Many SO_2 reduction schemes	Low efficiency and/or high cost

After the above elimination, about 100 of the most attractive strategies were fully evaluated, i.e., calculated by the STRAT program. Of these, about half were rejected when complete results were available for judgment -- basically for similar reasons as those that did not pass the first screening.

A total of 44 strategies was considered to have the greatest merit or potential and these are set forth in Tables C-1, C-2, and C-3. In some cases, the same strategy (such as a specific fuel switch) appears in more than one table as its effectiveness on more than one pollutant is measured. In such duplicate entries, the number of units and costs are the same; the emission effect, efficiency and specific cost are different.

The strategies were evaluated by means of the methods, procedures, formulae and assumptions set forth in Section V. The greatest bulk of this work was done by means of the computer employing the STRAT program; some simple extension of numbers and other tasks were performed by hand. The result of this work, for the selected strategies as outlined above, are set forth in the following tables.

Section VI contains the analysis upon which is based the selection of the few last alternative strategies that have been proposed as offering the most promising paths to abatement from the subject boiler group.

The following examples are simple illustrations of how the costs were computed for typical strategies. In actual practice, most table entries were the summation of multiple computer calculations for the several regions, fuels, boiler sizes, etc.

SAMPLE CALCULATION

Fuel Switch: Coal to Gas

User:	Commercial
Size Unit:	37,000 pph
Region:	Great Lakes
Efficiency:	77%
Load Factor:	35%

Fuel Costs (Table 5-1)

Coal @ $\$0.34/10^6$ Btu

Gas @ $\$0.38/10^6$ Btu

Btu Input

$$\frac{100}{77} \times 37{,}000 \text{ pph} \times \frac{975 \text{ Btu}}{\text{lb steam}} = 46.8 \times 10^6 \frac{\text{Btu}}{\text{hr}}$$

Yearly Fuel Cost

Gas $\frac{\$0.38}{10^6 \text{ Btu}} \times 46.8 \times 10^6 \frac{\text{Btu}}{\text{hr}} \times 8{,}760 \frac{\text{hr}}{\text{yr}} \times .35 = \$54{,}500/\text{yr}$

Coal $\frac{0.34}{0.38} \times 54{,}500 = \$47{,}700/\text{yr}$

Increased Fuel Cost = $6,800/yr

Boiler Conversion Cost (Table 5-3) = $25,000

Fuel Cost Increase	= $6,800
Annualization (@ 14.3%)	= 3,570
TOTAL OPERATING COST OF FUEL SWITCH	$10,370/year

SAMPLE CALCULATION

SO_2 Removal

Scheme C (from TVA) -- Dry $CaCO_3$ + Collector

User: Industrial
Location: Atlantic
Fuel: Pulverized or cyclone coal
Sulfur: 1.83%
Age: All
Size Boiler: 275,000 pph

The following cost breakdown was derived from Stone & Webster cost data:

	New Unit		Conversion Unit	
Capital Cost	$476,000		$578,000	
Capital cost minus precipitator credit	360,000		520,000	
Direct Cost				
Raw materials (6460 tons @ $5/ton)	32,300		32,300	
Operating Labor	5,000		5,000	
Utilities (452,000 kwhr @ $0.016/kwhr)	7,230		7,230	
Disposal (4540 tons @ $5/ton)	22,700		22,700	
Maintenance (5% of capital cost)	23,800		28,900	
Subtotal Direct Cost		91,030		96,130
Indirect Cost				
Capitalization (21% of capital cost)	100,000		121,400	
Overhead	500		500	
Subtotal Indirect Cost		100,500		121,900
TOTAL ANNUAL OPERATING COST	$191,530		$218,030	

TABLE C-1

STRATEGIES FOR PARTICULATE REDUCTION - 1975

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/lb)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Size WT1: Watertube Boilers; 1.421 x 10^6 tons Particulate Emissions in 1975 (based on present trends)						
Dry cyclones on stokers ≤ 20 years old; now 50% uncontrolled	0.3628	5.03	0.0069	13.15	1,787	25.6
Dry cyclones on stokers > 20 years old; now 90% uncontrolled	0.4717	6.83	0.0072	18.59	2,527	33.2
Switch coal to RO in AT & SE, to GS all other regions	1.287	95.0	0.0366	235.7	7,918	90.6
Fuel additive in all RO & DO units (after fuel switch)	0.057	6.79	0.0596	0	11,296	4.0
Sizes WT2&3: Watertube Boilers; 0.5613 x 10^6 tons Particulate Emissions in 1975 (based on present trends)						
Dry cyclones on: a) size 2, 20-30 yrs, pulv, 5% of units b) size 2, 10-20 yrs, stoker, 15% of units c) size 2, 20-30 yrs, stoker, 15% of units	0.0510	0.42	0.0041	1.855	42	9.1

TABLE C-1 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/lb)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Sizes WT2&3 (continued)						
d) size 3, 10-20 yrs, stoker, 10% of units e) size 3, 20-30 yrs, stoker, 20% of units						
Switch coal to RO in AT & SE, to GS all other regions	0.4959	139.2	0.142	208.4	1,906	88.3
Fuel additive in all RO & DO units (after fuel switch)	0.0228	4.1	0.0899	0	2,093	4.1
Sizes FT & CI: Firetube Boilers and Cast Iron; 0.5489 x 10^6 tons Particulate Emissions in 1975 (based on present trends)						
Switch coal to RO all regions all units < 20 yrs old	0.2702	91.5	0.191	582.0	79,197	49.2
Fuel additive in all RO & DO units (after fuel switch)	0.0943	8.63	0.130	0	779,894	17.2
Dry cyclones on units ≤ 20 yrs old (90% of units)	0.2496	15.05	0.030	61.33	71,277	45.5

TABLE C-1 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/lb)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Sizes FT & CI (continued)						
Switch coal to DO in AT & SE; to gas in all other regions; present RO to Lo-S RO all regions	0.3489	428.4	0.614	459.0	116,862	63.5

TABLE C-2

STRATEGIES FOR SO_2 REDUCTION - 1975

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/1b)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Size WT1: Watertube Boilers; 2.410 x 10^6 tons SO_2 Emissions in 1975 (based on present trends)						
SO_2 scheme B applied to stokers and RO units < 10 years old	0.6062	174.9	0.1442	382.5	3,873	25.1
SO_2 scheme B applied to stokers and RO units $\geq$ 10 years old	1.369	430.3	0.1572	1,194.0	9,482	56.8
SO_2 scheme F applied to stoker and RO units < 10 years old	0.5743	192.9	0.1678	485.7	3,873	23.8
SO_2 scheme F applied to stoker and RO units $\geq$ 10 years old	1.297	538.1	0.2075	1,466.0	9,482	53.9
SO_2 scheme C applied to RO units < 10 years old	0.091	104.7	0.577	327.6	2,022	4.7
SO_2 scheme C applied to RO units $\geq$ 10 years old	0.205	285.9	0.697	906.0	4,950	10.6
Switch coal to RO in AT & SE, to GS all other regions	1.216	94.09	0.0387	235.7	7,918	50.4

TABLE C-2 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/lb)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Size WT1 (continued)						
Switch coal to Lo-S RO in AT & SE, to GS all other regions; present RO to Lo-S RO in all regions	2.023	378.3	0.0935	235.7	7,918	84
Sizes WT2&3: Watertube Boilers; 3.239 x 10^6 tons SO_2 Emissions in 1975 (based on present trends)						
SO_2 scheme B applied to all coal & RO units < 10 years old	1.237	192.7	0.0779	233.7	1,007	38.3
SO_2 scheme B applied to all coal & RO units ≥ 10 years old	1.835	391.5	0.1067	675.3	2,044	56.7
SO_2 scheme F applied to all coal & RO units < 10 years old	1.172	178.6	0.0762	264.2	1,007	36.2
SO_2 scheme F applied to all coal & RO units ≥ 10 years old	1.738	378.4	0.1089	745.1	2,044	53.7
SO_2 scheme C applied to pulv, cyclone & RO units < 10 years old	0.446	122.17	0.1368	285.0	850	17.3

TABLE C-2 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost (\$$10^6$)	Specific Cost (\$/lb)	Capital Cost (\$$10^6$)	Units Changed	% Reduction
Sizes WT2&3 (continued)						
SO_2 scheme C applied to pulv, cyclone & RO units $\geq$ 10 years old	0.609	249.0	0.2043	673.4	1,638	23.6
SO_2 scheme D applied to pulv, cyclone & RO units < 10 years old	1.0057	148.7	0.074	231.8	850	31.1
SO_2 scheme D applied to pulv, cyclone & RO units $\geq$ 10 years old	1.3706	287.8	0.1048	605.5	1,638	42.4
Switch coal to RO in AT & SE; to GS all other regions	1.785	139.2	0.0394	197.4	1,906	55.2
Switch coal to Lo-S RO in AT & SE, to GS all other regions; present RO to Lo-S RO in all regions	2.876	336.9	0.0588	197.4	1,906	88.8
Sizes FT & CI: Firetube Boilers and Cast Iron; 1.983 x 10^6 tons SO_2 Emissions in 1975 (based on present trends)						
Switch coal to RO, all regions, all units < 20 years old	0.293	91.5	0.253	582.0	79,197	14.8

TABLE C-2 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost ($\$10^6$)	Specific Cost ($/lb)	Capital Cost ($\$10^6$)	Units Changed	% Reduction
Sizes FT & CI (continued)						
Switch all coal to DO, all regions, all units	0.6815	303.5	0.2841	776.5	116,862	34.3
Switch all coal to DO in AT & SE, to GS all other regions; present RO to Lo-S RO all regions	1.452	428.4	0.1475	459.0	116,862	73.2

TABLE C-3

STRATEGIES FOR NO_x REDUCTION - 1975

Description	Annual Reduction (10^6 tons)	Annual Cost ($\$10^6$)	Specific Cost ($/1b)	Capital Cost ($\$10^6$)	Units Changed	% Reduction
Size WT1: Watertube Boilers; 0.6202 x 10^6 tons NO_x Emissions in 1975 (based on present trends)						
All oil & gas units operated with LEA*	0.1099	6.11	0.0278	61.1	20,377	17.7
Switch coal to RO in AT & SE, to GS all other regions	0.1331	95.0	0.353	235.7	7,918	21.4
All oil & gas units operated with FGR**	0.1099	12.2	0.0555	122.0	20,377	17.7
Both LEA & FGR applied to all oil & gas units	0.1830	16.3	0.0445	163.0	20,377	29.5
After coal switch to RO & GS, apply LEA & FGR to all units	0.2680	22.6	0.042	226.0	28,295	64.7
Sizes WT2&3: Watertube Boilers; 0.8846 x 10^6 tons NO_x Emissions in 1975 (based on present trends)						
All oil & gas units operated with LEA	0.1166	0 (due to fuel savings)	0	13.66	3,416	13.2
Switch coal to RO in AT & SE, to GS all other regions	0.2710	134.2	0.260	197.4	1,906	30.6

TABLE C-3 (continued)

Description	Annual Reduction (10^6 tons)	Annual Cost ($\$10^6$)	Specific Cost (\$/lb)	Capital Cost ($\$10^6$)	Units Changed	% Reduction
Sizes WT2&3 (continued)						
Both LEA & FGR applied to all oil & gas units	0.1945	0	0	75.2	3,416	23.0
After coal switched to RO & GS, apply both LEA* & FGR** all units	0.3500	0	0	117.1	5,322	73.4
Sizes FT & CI: Firetube Boilers and Cast Iron; 0.5738 x 10^6 tons NO_x Emissions in 1975 (based on present trends)						
All oil & gas units operated with LEA or FGR	0.1576	510.0	1.62	5,100.0	1,702,205	27.5
Switch coal to DO in AT & SE, to GS all other regions; present RO to Lo-S RO all regions	0.0572	428.4	3.75	459.0	116,862	9.96
Both LEA & FGR applied to all oil & gas units	0.2623	715.0	1.36	7,150.0	1,702,205	45.8
After coal switched to Lo-S RO & GS, apply LEA & FGR to all units	0.3411	765.0	1.34	7,650.0	1,819,067	59.4

---

*LEA = low excess air

**FGR = flue gas recirculation